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1988 RELIABILITY ASSESSMENT

THE FUTURE OF BULK ELECTRIC SYSTEM RELIABILITY IN NORTH AMERICA 1988-1997

North American
Electric
Reliability
Council

North American Electric Reliability Council

ECAR
East Central Area Reliability Coordination Agreement

ERCOT
Electric Reliability Council of Texas

MAAC
Mid-Atlantic Area Council

MAIN
Mid-America Interconnected Network

MAPP
Mid-Continent Area Power Pool

NPCC
Northeast Power Coordinating Council

SERC
Southeastern Electric Reliability Council

SPP
Southwest Power Pool

WSCC
Western Systems Coordinating Council

AFFILIATE

ASCC
Alaska Systems Coordinating Council

The North American Electric Reliability Council (NERC) was formed in 1968 by the electric utilities to promote the RELIABILITY of their generation and transmission systems. NERC consists of nine Regional Reliability Councils and one affiliate encompassing virtually all of the electric systems in the United States, Canada, and the northern portion of Baja California, Mexico.

RELIABILITY, in a bulk electric system, is the degree to which the performance of the elements of that system results in electricity being delivered to customers within accepted standards and in the amount desired. The degree of reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply (or service to customers).

Bulk electric system reliability can be addressed by considering two basic and functional aspects of the bulk electric system — adequacy and security.

ADEQUACY is the ability of the bulk electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and unscheduled outages of system components.

SECURITY is the ability of the bulk electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system components.

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North American Electric Reliability Council

September 1988

Foreword

About the Council

The North American Electric Reliability Council (NERC) was formed in 1968 by the electric utilities to promote the RELIABILITY of their generation and transmission systems. NERC consists of nine Regional Reliability Councils and one Affiliate encompassing virtually all of the electric utility systems in the United States, Canada, and the northern portion of Baja California, Mexico.

The governing body of the Council is its Board of Trustees. It consists of two representatives from each Regional Reliability Council plus additional Trustees as necessary to assure at least one representative from a Canadian utility system and at least two representatives from each segment of the electric utility industry: investor-owned, federal, rural electric cooperative, and state municipal.

Meetings of the Board are attended by observers from the U.S. Department of Energy, the U.S. Federal Energy Regulatory Commission, the Canadian National Energy Board, the Edison Electric Institute, the American Public Power Association, the National Rural Electric Cooperative Association, and the Canadian Electrical Association.

The overall activities of the Council are directed by its Board of Trustees. Its technical activities are carried out by its Operating and Engineering Committees and their subgroups comprised of managerial and technical experts from the nine Regional Reliability Councils. The NERC staff, located in Princeton, New Jersey, provides coordination and support for the Council's overall activities.

About this Report

The NERC Board of Trustees created the Interregional Review Subcommittee in 1970 to review, on a continuing basis, the overall reliability of the existing and planned generation and transmission systems of the nine Regional Reliability Councils. The Subcommittee's name was changed in 1987 to the Reliability Assessment Subcommittee (RAS) to be more descriptive of the Subcommittee's function.

This 1988 Reliability Assessment report presents:

- An assessment of electric generation and transmission reliability through 1997.
- A discussion of the key factors and issues affecting future electric supply, and
- Detailed Region-by-Region assessments of electric supply reliability, including those issues of specific regional concern.

In preparing this report, the RAS interviewed representatives of selected Regions and reviewed detailed self-assessments prepared by each of the nine Regional Reliability Councils, including aggregate forecasts of peak demand and planned capacity resources on a regional and national basis. They also appraised regional plans and commitments for future electric generation and transmission facilities, and assessed the potential effect of legislation, regulations, and governmental policies on future electric supply reliability. This report is the culmination of these efforts and reflects the expertise, judgment, and interpretations of the RAS members.

Unless otherwise noted, the data presented in the figures and tables reflect conditions as of January 1, 1988. Data has been extracted from the April 1, 1988 Coordinated Bulk Power Supply Program (IE-411) Reports submitted to the U.S. Department of Energy by each Regional Reliability Council and from regional data submittals made directly to the RAS. Detailed background information on projected peak demands, annual energy requirements, generating capabilities, transmission, and fossil fuel requirements are presented in a companion NERC report "1988 Electricity Supply & Demand for 1988-1997."

1988 Reliability Assessment

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Executive Summary

Electricity supply is expected to be adequate in most parts of the United States and Canada over the next ten years. However, many forces and trends are creating risks to this future supply. If the following forces and trends are not carefully managed, the specific problems identified in this Reliability Assessment could become commonplace.

Growth in the Demand for Electricity – This year's ten-year forecast of peak demands is slightly higher than last year's. Utility plans will support the forecast annual growth in peak demand of 1.9% in the United States and 2.5% in Canada. There is a 50% chance that annual growth will be greater than forecast, and a 10% chance that growth will exceed 2.6% in the United States and 3.5% in Canada. If demand grows faster than forecast, supply deficiencies could occur.

Economy versus Reliability – External forces are causing economic goals to encroach upon bulk electric system reliability goals. These forces and trends could lower reliability and lead to higher cost to the customer if a proper balance is not maintained.

Public Policy Disincentives – Uncertain regulatory treatment is discouraging electric utilities from incurring the financial risk associated with major generation projects. Changing and conflicting federal, state, provincial, and local policies continue to delay the construction of needed generation and transmission facilities. These policies may ultimately erode the reliability of electric supply. Utilities and public policymakers must work together to reduce these uncertainties and conflicts to restore flexibility in planning.

Transmission Access and Deregulation – Transmission systems cannot be designed for unlimited access. Use of utility-owned facilities to transfer electricity among utilities and non-utilities must be by mutual agreement and must be properly planned, scheduled, and controlled to maintain electric system reliability.

Environmental Considerations – Both new and existing generation and transmission facilities can be affected by environmental legislation. Stringent requirements may reduce system reliability without achieving significant environmental or health benefits. Sound technical evaluations of the potential effects of proposed legislation on the environment and on electric system reliability are needed.

Non-Utility Generation – Nearly one-fourth of the planned capacity additions over the next ten years are projected to be non-utility generators. To maintain system reliability, these units must be designed and operated according to the same technical requirements as utility generators.

This Reliability Assessment identifies several geographic areas where electric system reliability is at serious risk. Emergency measures, including controlled interruptions of customers' supply, are possible in these areas.

NPCC – Peak demand and capacity projections indicate that additional resources beyond those already planned and committed will be required in New England beginning in 1993. If the Seabrook unit is not permitted to operate, these additional resources will be required at least one year earlier. Loss of the Shoreham unit in a Region where capacity shortages may occur in the early 1990s is of great concern.

MAAC – Heavy interregional transmission loadings can impair reliability by limiting the ability of MAAC to receive emergency assistance from utilities in other Regions. The extended delay of two sections of the Baltimore-Washington 500 kV loop limits interregional transfer capability and reduces reliability in the Baltimore and Washington, D.C. areas.

ERCOT – Construction of several 345 kV transmission lines has been blocked resulting in inadequate transmission in the Region. Certain transmission facility outages could interrupt the electricity supply to Austin, Texas.

SERC – Construction of a 500 kV transmission line in Florida continues to be delayed. For the near term, higher cost local generation can be used to maintain system reliability. Eventually, reliability will be reduced until the line can be constructed.

Electric utility customers expect a reliable supply of electricity. That supply is threatened. Public policymakers must work in partnership with utilities to manage the public policy issues which threaten future electric system reliability.

Reliability and What It Means to the Customer

Consequences of Inadequate Reliability

Most electric utility customers have experienced the effects of an electric supply disruption. In such circumstances, many of the modern conveniences and basic necessities taken for granted become unavailable. The lights are out. Clocks may stop. Space heating or cooling is off and even hot water and water pressure may be affected. Commercial and industrial operations are interrupted. Even routine tasks such as cooking and eating may become difficult.

Fortunately, the majority of electric system disruptions are confined to individual neighborhoods or localized areas where, perhaps due to severe weather or equipment failure, electric service is interrupted. However, on occasion, deficiencies in either the generation or transmission segments of the electric system can develop which may result in major electric system disturbances interrupting the electrical supply to large numbers of customers over a widespread geographic area. This report is concerned with assessing the future reliability of the generation and transmission segments of electric utility systems.

Major Electric System Disturbances

Widespread electric supply disruptions can have chilling and far-reaching effects on society. They can produce a myriad of impacts which can bring an electrified, computer-dependent, highly-automated society to an abrupt halt.

An example of the widespread effects of a major electric system disturbance is the electrical blackout that hit the Northeastern part of North America in 1965. This disturbance directly affected the lives of 30 million people and was the worst electric supply outage in U.S. history in terms of the number of people involved.

The disturbance occurred on November 9, 1965 shortly after 5 p.m. The commercial and industrial complex of the northeastern United States was in the process of shutting down for the night. Within minutes of the disturbance:

- More than 600,000 people were stranded on subways.
- Loss of lighting necessitated massive cancellation and diversion of air flights.
- Over 850 hospitals were without commercial electricity. In New York City only half of the 150 hospitals had adequate emergency electric supply.
- Many telephones were out of service, and all forms of telecommunications were impaired.
- Massive traffic jams occurred due to failure of traffic control systems.
- Police, doctors, and firemen were without normal communications.
- Elevators were inoperative in high-rise buildings.

The shutdown was more complete than anyone could have imagined, taking up to 13 hours to restore electric service to most of the affected area. Economic losses were estimated at about $100 million.

In another widespread electric system disturbance on July 23, 1987, a large portion of Tokyo, Japan was blacked out affecting some 2.8 million electric customers. Similar to the 1965 Northeast blackout, the Tokyo Electric Power Company reported widespread disruption of train, subway, elevator, and vehicular traffic. Water supply was suspended in many areas. In addition, and perhaps just as critical from an economic perspective, computer services were lost, making on-line equipment of business and financial institutions unusable.

More recently, on April 18, 1988, the Canadian province of Quebec experienced a system-wide blackout due to severe weather conditions and multiple transmission and generation equipment outages. Electric service to about six million people was interrupted for periods up to eight hours.

The electric system blackouts described above fortunately have been infrequent occurrences in our twentieth century society. They are indicative, however, of what can occur when generation or transmission electric system reliability is compromised.

Socioeconomic Impacts

Electricity has become an irreplaceable part of our way of living and conducting business. It is so second nature that it is literally taken for granted. Electric supply interruptions caused by inadequate reliability can range from minor customer inconveniences to a complete shutdown of commercial, industrial, and residential activity with major economic loss, looting, and even endangerment of human life. The more advanced our society becomes, the greater are the benefits of reliable electric service and the greater are the societal impacts caused by unreliable or poor quality electric service.

If widespread electric supply interruptions occurred more frequently in any region, the accumulated loss of product could prevent a business from meeting production schedules. Lost revenues and lower production could cause businesses to close or relocate to areas where electric supply is considered more reliable. Loss of industrial activity would soon be accompanied by a decline in commercial and residential growth.

Reliable electric supply is not only valuable to the individual customer, but is crucial to the economic health of a region and the continent as a whole. Although the cost of major electric system disturbances can be extremely high, 100% reliability is not practical. Utilities and public policymakers must carefully balance the cost of outages and the cost of supply.

Protection Against Inadequate Reliability

The U.S. and Canadian electric utilities operate interconnected generation and transmission networks dedicated to meeting the electrical requirements of their customers through well coordinated planning and operations to assure that the supply of electricity is always equal to customer demand.

Since the 1965 Northeast blackout, many changes have been made to electric generation and transmission systems to reduce the likelihood and the impacts of such disturbances. The electric utility industry has built a strong record of reliability and is striving to maintain that record.

From time to time, however, conditions can occur for which electric systems are not designed. Even when supply margins appear adequate, extraordinary events can place systems in a vulnerable position. Typical examples include an unusual amount of unavailable generation, multiple outages of segments of the transmission systems, or unexpectedly high customer demand. When these conditions occur and if time permits, utilities will rely on emergency procedures to reduce customer electric demand to protect against uncontrolled shutdown of the entire electric system and damage to equipment.

Emergency operating procedures are generally implemented after all available electrical generating sources have been called upon and after all contractually interruptible customer loads have been interrupted. These procedures include public appeals to customers to voluntarily reduce their electrical demands, utility instituted system voltage reductions, and utility controlled customer load shedding. Although these actions may result in customer inconvenience, they are far less disruptive than widespread uncontrolled system disturbances.

Electric utilities, policymakers, and the public share the responsibility of ensuring that an adequate level of bulk electric system reliability is available to meet future electrical service requirements. All segments of society must work together in support of a continuing adequate, reliable, and affordable electric supply. Electric system reliability should not be allowed to be compromised under the guise of short-term economic benefits which in the longer term could result in economic penalties and a degradation in electric service.

The chapters that follow present, in substantial detail, the electric utilities' view of electric system reliability over the next ten years and the major challenges to that reliability.

Peak Demand and Energy

There are projections of peak demand and annual energy levels are slightly higher in the United States and Canada than those made last year.

The uncertainty in the projections of a 1.9% per year average growth in peak demand in the United States and 2.5% per year in Canada is illustrated by the bandwidth around each of these base forecasts. For the United States, the bandwidth indicates that there is an 80% probability that peak demand will increase at an annual rate between 1.0% and 2.6% over the 1988-1997 period. For Canada, the increase will be between 1.1% and 3.5% with the same probability.

Utilities in all Regions are using demand management programs to reduce system peak demands and to defer the need for generation capacity additions. More experience will be required to establish the long-term availability, effectiveness, and customer acceptance of some of these programs.

Recent Experience

All 1987 peak demand and annual energy forecasts for the NERC areas of the United States and Canada were exceeded, as shown in Table 1. The demand for electricity was higher than expected, primarily in the eastern two-thirds of the United States and Canada, due mainly to extreme seasonal weather conditions. Figure 1 shows the twelve-month running average growth rates for annual energy over the last few years. The long-term strength of these recent growth trends is of concern to electric utility load forecasters and especially to electric system planners responsible for the adequacy of future generation and transmission supplies.

1988-1997 Forecast

The electric peak demand in the United States is projected to grow at 1.9% per year, and the United States is expected to continue to be summer peaking over the 1988-1997 forecast period. Canada is projected to be winter peaking throughout the same period with its peak demand growing at 2.5% per year. These peak demand forecasts and the annual net energy for load projections are summarized in Table 2. In the United States, the ten-year forecast of summer peak demand is slightly higher in magnitude than the 1987 ten-year forecast and about the same as the 1986 forecast. In Canada, the ten-year forecast of winter peak demand is slightly higher than the ten-year forecasts made in 1987 and 1986.

Individual peak demand and annual energy forecast data for each of the nine Regional Reliability Councils is presented in the respective regional assessment chapters of this report. Forecast peak demand levels have increased in six Regions and decreased in three Regions compared to last year's forecast. Regional peak demand average annual growth rates range from 1.3% to 2.4%.

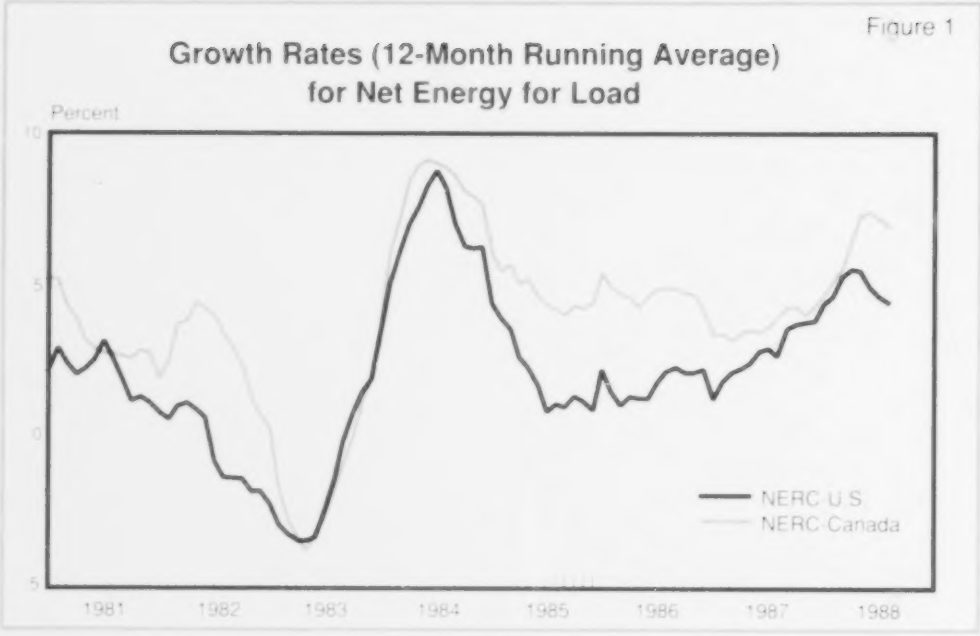
Forecast Uncertainty

The NERC projections of peak demand and annual energy are aggregates of the baseload forecasts as of January 1988 of the individual utilities comprising the nine Regional Reliability Councils. It is intended that the probability of exceeding the base forecast is equal to the prob-

Table 1 – 1987 Actual Peak Demand and Energy

	1986 Actual	1987 Actual	Actual Change %	1987 Forecast	Actual vs Forecast %
NERC-U.S.					
Summer Peak Demand (Thousands of MW)	477	496	4.0	484	2.4
Annual Net Energy for Load (Millions of MWh)	2,532	2,644	4.4	2,589	2.1
NERC-Canada					
Winter Peak Demand (Thousands of MW)	64	70	8.9	68	2.7
Annual Net Energy for Load (Millions of MWh)	357	375	5.0	374	0.3

Figure 1



ability of the forecast not being reached. That is, there is a 50% chance that the base forecasts will be exceeded and a 50% chance that the base forecasts will not be reached.

Because electric demand and annual electrical energy requirements are reflections of the ways in which customers use electricity in their domestic, commercial, and industrial activities, the utilities' forecasts are subject to change. Utilities continually monitor their peak demand and energy requirements and typically update their forecasts every year.

To avoid implying a degree of certainty not intended in the ten-year forecasts, bands of reasonable variation about the forecasts have been developed. The sensitivity bandwidths for the 1988-1997 aggregated peak demand forecasts for the United States and Canada are shown in Figures 2 and 3, respectively.

In developing the U.S. bandwidth, the variables which were found to relate best to growth in electrical energy were the gross national product, the price of electricity, and the price of natural gas. Relationships between these variables and annual net energy for load were determined. High and low estimates of the variables were then selected to develop high and low annual energy projections about the base annual energy forecast. The summer peak demand bandwidth of Figure 2 was estimated by applying the annual load factors from the NERC aggregated base forecasts to the high and low energy bounds along with consideration of the historical relationship between peak

Table 2 – 1988-1997 Forecast of Peak Demand and Energy

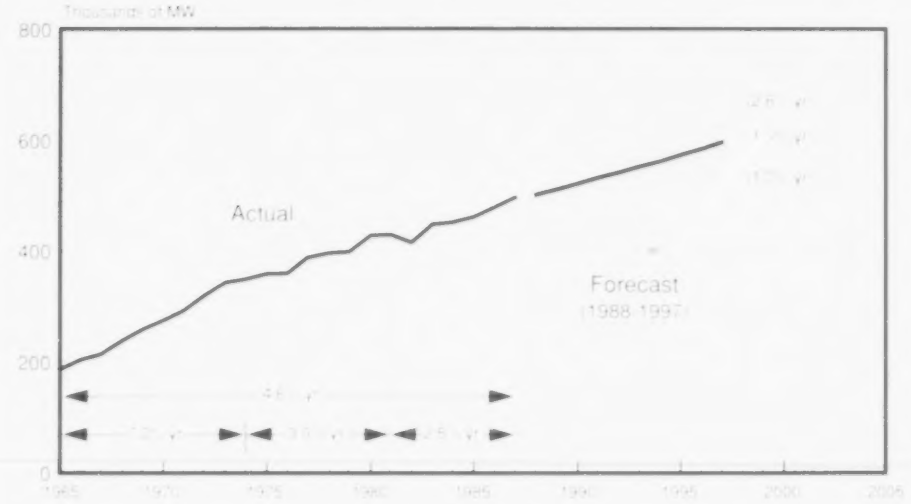
	1988	1997	Average Growth 1988-1997 (%/yr)
NERC–U.S.			
Summer Peak Demand (Thousands of MW)	500	594	1.9
Annual Net Energy for Load (Millions of MWh)	2,690	3,210	2.0
NERC–Canada			
Winter Peak Demand (Thousands of MW)	71	88	2.5
Annual Net Energy for Load (Millions of MWh)	391	502	2.8

demand and annual energy. The resulting bandwidth range of peak demand growth rates for the United States is 1.0% to 2.6% per year. This bandwidth has been defined such that there is an 80% probability that the future U.S. summer peak demands will fall within the bandwidth. That is, there is a 10% chance that future peak demands will exceed the upper bound, and a 10% chance that future demands will be less than the lower bound.

The predictor variables used in developing the Canadian winter peak demand 80% bandwidth are the domestic national product, the price of electricity, heating degree days, a weighted average of the price of natural gas and oil, and the effect of marketing efforts in the industrial sector. The resulting range of average annual winter peak demand growth rates in Canada is 1.1% to 3.5%. The Canadian and U.S. forecast bandwidth calculation methodologies are similar except for the variables.

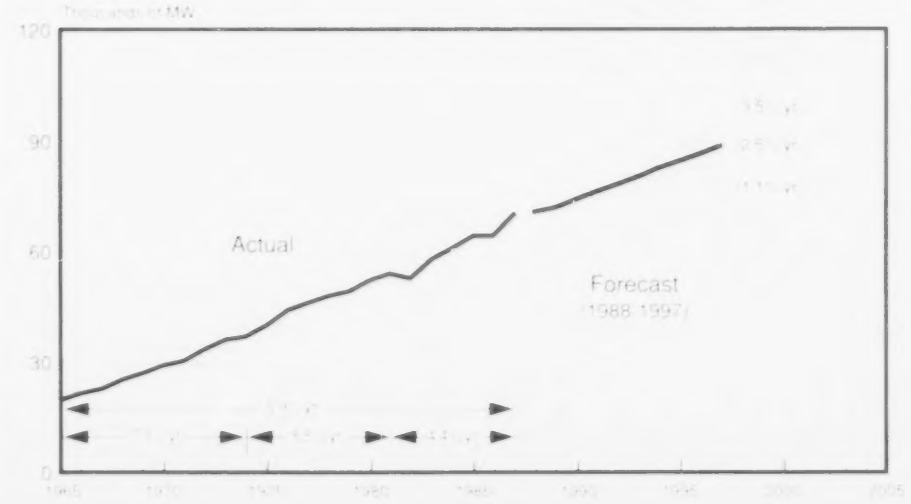
NERC-U.S. Figure 2

Summer Peak Demand Bandwidth



NERC-Canada Figure 3

Winter Peak Demand Bandwidth



Demand Management

Load Management

Peak Demand Forecast

It would be incorrect and misleading to apply the ranges of the forecast bandwidths shown in Figures 2 and 3 to the forecasts of any of the nine Regional Reliability Councils or to the forecasts of individual utilities since the bands shown represent a composite of all member utilities in each country.

Demand Management and Load Management

Demand management programs provide the utility with the ability to reduce peak demand and thus possibly delay the need for some future electric generating capacity. However, demand management is not an unlimited resource. It may reduce the rate of growth in peak demand, but it will not eliminate growth. Some utilities have been heavily involved in these demand reduction or peak shifting programs for many years, while other utilities are just initiating programs now as a means of gaining experience and to provide for flexibility in the future. However, some utilities will be heavily dependent on the success of these programs in satisfying their generating capacity margin requirements over the next ten years.

Load management is that portion of demand management under the direct control of electric utility system operators and is generally included in (not subtracted from) the peak demand forecasts mentioned earlier. It is being employed to various degrees throughout NERC. A survey of load management experts indicated an achievable reduction of peak demand in the range of 3% to 6% on an aggregate basis. The long-term effects and availability of load management have yet to be proven. The projected extent to which load management can reduce peak demand over the next ten years is discussed and illustrated in the "Assessment of Generation Reliability" chapter.

Assessment of Generation Reliability

1988-1997 Capacity Projections

Capacity additions of 90,500 MW are planned for NERC over the 1988-1997 forecast period. The forecast summary of generating unit additions, retirements, and oil-to-coal conversions is shown in Table 3.

Table 3 – Generating Unit Additions, Retirements, and Conversions (1988-1997)

	NERC-U.S.		NERC-Canada		NERC-Total	
Type	Thousands of MW	% of Total	Thousands of MW	% of Total	Thousands of MW	% of Total
Nuclear	18.2[a,b]	24.8	3.5	21.5	21.7[a,b]	24.0
Coal	15.4	21.0	4.1	25.1	19.5	21.5
Hydro	1.7	2.3	8.0	48.7	9.7	10.7
Oil/Gas	13.6	18.5	0.5	3.0	14.7	16.2
Pumped Storage	2.1	2.9	0.0	0.0	2.1	2.4
Other (Utility)	2.6	3.5	0.0	0.0	2.7	3.0
Non-Utility Generators	19.8	27.0	0.3	1.7	20.1	22.2
Additions	73.4	100.0	16.4	100.0	90.5	100.0
Retirements	7.1		0.2		7.3	
Conversions (Oil to Coal)	0.3		0.0		0.3	

Note: Figures are rounded. Percentages are based on complete data.
[a]Includes the Shoreham 809 MW nuclear unit.
[b]Perry 2 and Washington Nuclear Project units. WNP 1 and 3, are not included.
[c]Includes 0.6 MW of oil-fired and 0.1 MW of geothermal additions in that part of the Comision Federal de Electricidad system in the northern portion of Baja California, Mexico, which is interconnected with the U.S. systems.

Coal and nuclear generating units account for 45.8% of the U.S. generating capacity additions over the next ten years. Non-utility generators (NUGs) will comprise another 27%, while all other types of utility-owned generators will provide the remaining 27.2%. In Canada, nuclear, hydro, and coal-fired generating units will comprise 95.3% of the capacity additions. Oil- and gas-fired generators account for 3% and NUGs 1.7%.

Projected generating unit retirements in NERC of 7,300 MW (7,100 MW in the United States and 200 MW in Canada) are approximately 31% less than last year's ten-

Table 4 – Construction Status of Generating Unit Additions (1988-1997)

	NERC-U.S.			NERC-Canada		
	Number of Units	Thousands of MW	% of Total MW	Number of Units	Thousands of MW	% of Total MW
Nuclear[a]						
Not Yet Under Construction[b]	0	0.0	0.0	0	0.0	0.0
Under Construction (<50%)	0	0.0	0.0	2	1.8	50.0
Under Construction (>50%)	16	18.2	100.0	2	1.8	50.0
Total Nuclear	16	18.2	100.0	4	3.5	100.0
Coal						
Not Yet Under Construction[b]	18	5.9	38.3	11	3.0	72.4
Under Construction (<50%)	7	5.3	34.8	1	0.4	9.4
Under Construction (>50%)	7	4.2	26.9	2	0.7	18.2
Total Coal	32	15.4	100.0	14	4.1	100.0
Hydro[c]						
Not Yet Under Construction[b]	69	1.3	75.6	37	5.8	72.7
Under Construction (<50%)	8	0.1	7.4	14	2.2	27.3
Under Construction (>50%)	15	0.3	17.0	0	0.0	0.0
Total Hydro	92	1.7	100.0	51	8.0	100.0
Other (Utility)						
Not Yet Under Construction[b]	166	14.9	81.5	8	0.5	100.0
Under Construction (<50%)	16	2.3	12.4	0	0.0	0.0
Under Construction (>50%)	15	1.1	6.1	0	0.0	0.0
Total Other (Utility)	197	18.3	100.0	8	0.5	100.0
Non-Utility Generators (NUGs)						
Not Yet Under Construction	–	18.8	94.8	–	0.3	82.5
Under Construction (<50%)	–	0.5	2.5	–	0.1	9.8
Under Construction (>50%)	–	0.5	2.7	–	0.1	7.7
Total NUGs	–[d]	19.8	100.0	–[d]	0.3	100.0
Total (All Units)						
Not Yet Under Construction	–	40.9	55.7	–	9.5	58.0
Under Construction (<50%)	–	8.2	11.2	–	4.4	26.5
Under Construction (>50%)	–	24.3	33.1	–	2.5	15.5
Total (All Units)	–[d]	73.4	100.0	–[d]	16.4	100.0

Note: Figures are rounded. Percentages are based on complete data.
[a]Perry 2 and Washington Nuclear Project units, WNP 1 and 3, are in some stage of construction but are not included.
[b]Includes utility units planned but not utility authorized, units with regulatory approval pending, and units with regulatory approval received but not yet under construction.
[c]Does not include pumped storage.
[d]Non-utility generator additions are not available by unit.

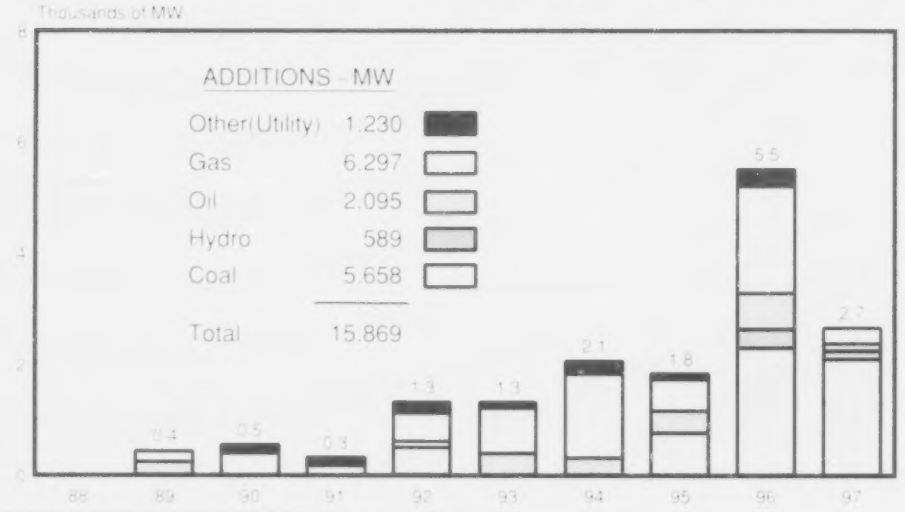
year retirement projections. The increased attention being given to extending the life of existing units and to improving availability is influencing decisions on capacity additions, deferrals, cancellations, and retirements.

Generating Unit Construction Status

All planned nuclear units for the forecast period are in some stage of construction, and all but two of them are over 50% complete. However, an agreement has been negotiated between the Long Island Lighting Company and New York state to close the 100% complete 809 MW Shoreham nuclear unit. The commercial operation of several other nuclear units in the United States is in question. Of the planned coal-fired units, 62% in the United States and 28% in Canada are in some phase of construction. This and similar data are shown for utility and non-utility capacity additions in Table 4. A substantial portion of

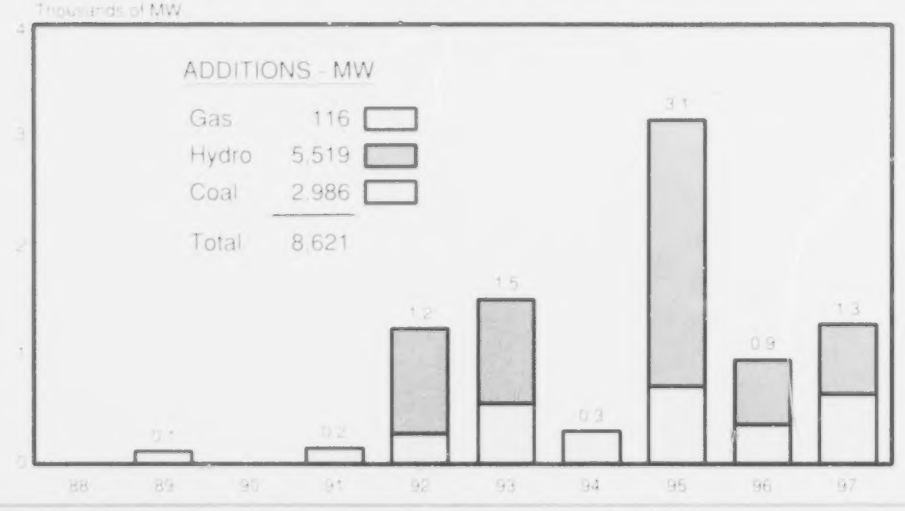
NERC-U.S. Figure 4

Utility-Owned Generator Unit Additions
100 MW or More – Not Yet Under Construction



NERC-Canada Figure 5

Utility-Owned Generator Unit Additions
100 MW or More – Not Yet Under Construction



hydro and other (utility) additions are not yet under construction, and 95% of the non-utility generation additions are not reported to be under construction.

About 24,500 MW, or 27% of the total planned additions in the United States and Canada, consist of utility-owned units 100 MW or larger which are not yet under construction. Figures 4 and 5 indicate that about 4,000 MW of these units have projected in-service dates of 1992 or earlier allowing less than five years for actual construction. In addition, about 15,400 MW of NUG units of various sizes, which are scheduled for service by 1992, are not reported to be under construction. It is likely that much of this 39,900 MW of new capacity will not be completed on schedule.

Non-Utility Generation

All nine Regional Reliability Councils have some level of NUG activity. By the summer of 1997, NUGs are projected to total approximately 27,900 MW or about 3.4% of NERC's 1997 total planned capacity resources. A regional breakdown of the 1997 NUG capacity is shown in Table 5.

Table 5 – Existing and Planned Non-Utility Generators (NUGs) by Summer 1997

Region	Total Projections MW	% of Total Capacity Resources
ECAR	2,308	2.2
ERCOT	2,506	4.2
MAAC	3,126	5.6
MAIN	12	0.1
MAPP	281	0.7
NPCC	4,857	3.6
SERC	5,910	3.6
SPP	582	0.9
WSCC	8,359	5.4
NERC-Total	27,941	3.4
NERC-U.S.	27,656	3.8
NERC-Canada	285	0.3

Included in the 27,900 MW of NUG capacity projected to be in service by 1997 are additions of about 20,100 MW over the 1988-1997 period. These NUG additions represent about 22% of total planned capacity additions. A breakdown of these units by fuel type is shown in Table 6. Of those NUGs with specified fuel types, 47% will use natural gas.

Table 6 – Non-Utility Generator Additions by Fuel Type

Fuel Type	1988-1997 MW	% of Total
Natural Gas	3,029	15.0
Hydro	500	2.5
Coal	1,315	6.5
Geothermal	594	3.0
Wind	84	0.4
Solar	100	0.5
Refuse (Solid Waste)	458	2.3
Wood/Wood Wastes	346	1.7
Other or Unknown	13,702	68.1
Total	20,128	100.0

Rapid growth in non-utility generation has occurred over the last few years. This growth has in many aspects benefitted both electric utilities and their customers. This projected use of NUG capacity has also prompted growth in reliability related concerns. These concerns are discussed in the "Non-Utility Generation" reliability issues chapter.

Non-Utility Generators

Table 7 – Projected Generating Capacity – 1996 Summer – NERC-U.S. Comparison of Forecasts

Projected Generating Capacity	This Year's Forecast For 1996 (Thousands MW)	This Year's Forecast % of Total	Last Year's Forecast For 1996 (Thousands MW)	Last Year's Forecast % of Total	Change in Forecast For 1996 (Thousands MW)
Coal	298.1	41.6	307.4	43.4	-9.3
Nuclear	107.2	14.9	107.5	15.2	-0.3
Hydro	68.0	9.5	70.4	10.0	-2.4
Oil/Gas	193.3	26.9	185.5	26.2	7.8
Pumped Storage	18.4	2.6	18.5	2.6	-0.1
Other (Includes NUGs)	32.3	4.5	18.4	2.6	13.9
Total	717.3	100.0	707.7	100.0	9.6

Note: Figures are rounded. Percentages based on complete data.

Comparison of Recent Capacity Projections

It is rather difficult to compare ten-year projections of generation capacity additions from year to year because of the many generating unit additions and cancellations, the rescheduling of service dates, and the planned retirements and deferrals. Tables 7 and 8 attempt this comparison for NERC-U.S. and NERC-Canada, respectively. These tables compare the projected installed generating capacity for the summer of 1996 in the United States (winter of 1996/97 in Canada), the last common year of last year's forecast and this year's forecast.

The U.S. total projected generating capacity in 1996 is about 9,600 MW higher than last year's forecast for 1996. Similarly, the total projected winter capacity for Canada in 1996/97 has increased by about 2,800 MW over last year's forecast. For the United States, capacity reductions of 11,700 MW in coal and hydro are overshadowed by the increase of 7,800 MW in utility gas- and oil-fired capacity and 13,900 MW of primarily non-utility generators. There is an increased reliance on gas- and oil-fired capacity and NUGs in the United States, while in Canada the capacity increases are primarily hydro and some oil- and gas-fired capacity.

Planned Capacity Resources Uncertainty

All future plans are subject to uncertainty, and plans for electric generating capacity are no exception. New utility units are subject to delays due to licensing, regulation, and public intervention, as well as to the complexities of completing any large project. Non-utility generation plans are also subject to variance from forecast due to the economic climate and, in some cases, regulatory and tax treatment.

The continued operation of today's installed utility generating capacity is also subject to uncertainty. For example, in addition to planned retirements, reratings, and the return of some presently idle capacity to service, the usable amount of today's capacity will likely decrease as that capacity ages. About 14% of the currently installed

Table 8 – Projected Generating Capacity – 1996/97 Winter – NERC-Canada Comparison of Forecasts

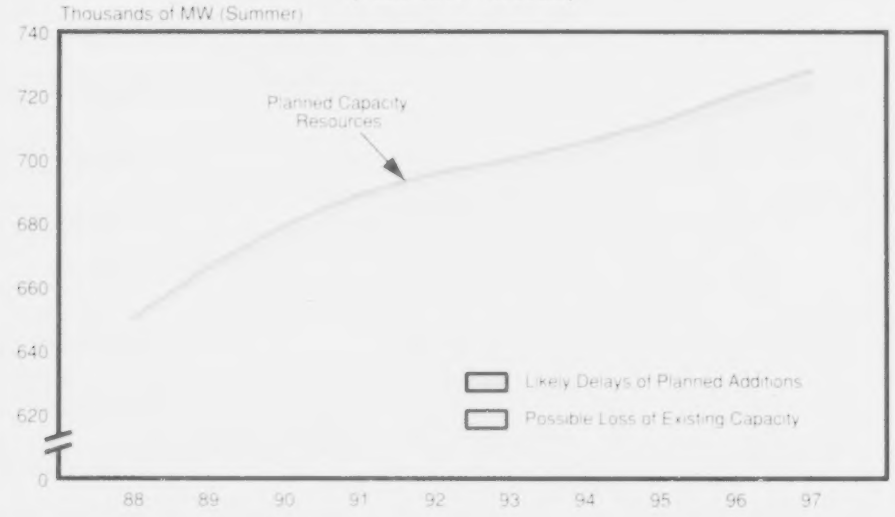
Projected Generating Capacity	This Year's Forecast For 1996/97 (Thousands MW)	This Year's Forecast % of Total	Last Year's Forecast For 1996/97 (Thousands MW)	Last Year's Forecast % of Total	Change in Forecast For 1996/97 (Thousands MW)
Coal	21.2	21.5	21.5	22.5	-0.3
Nuclear	15.6	15.7	15.6	16.2	0.0
Hydro	52.5	53.2	50.0	52.1	2.5
Oil/Gas	9.2	9.3	8.7	9.0	0.5
Pumped Storage	0.0	0.0	0.0	0.0	0.0
Other (Includes NUGs)	0.3	0.3	0.2	0.2	0.1
Total	98.8	100.0	96.0	100.0	2.8

Note: Figures are rounded. Percentages based on complete data.

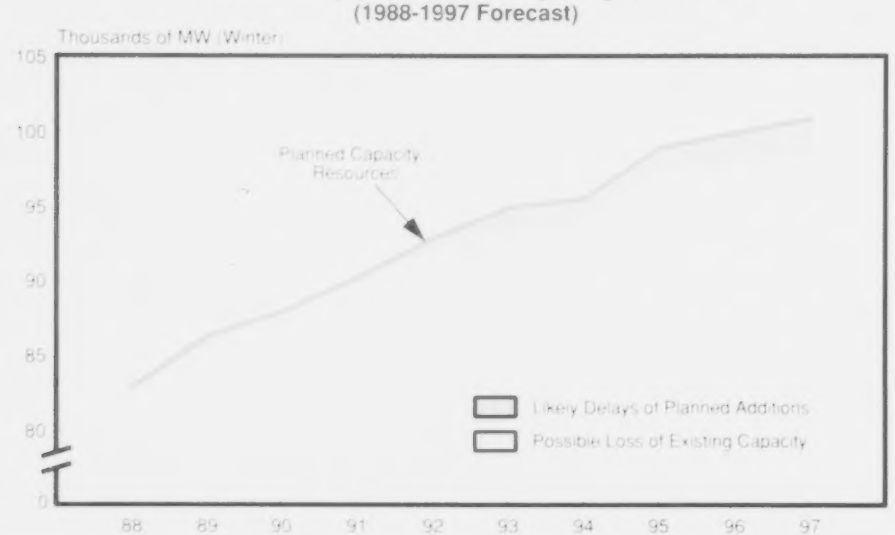
U.S. coal-fired capacity (6% in Canada) will be over 40 years old by the end of the assessment period. Similarly, about 16% of the current U.S. oil- and gas-fired capacity (10% in Canada) will be over 40 years old. The extent to which older capacity will continue to be available for service is dependent upon the economic viability of continued operation and the success of generating plant refurbishment efforts currently under way at many utilities. In addition, future environmental legislation and regulations concerning acid rain could result in some reduction in unit output of existing coal-fired capacity, as well as the removal from service of some existing coal-fired capacity where increased environmental restrictions cannot be economically attained.

Planned capacity resources include existing and planned generating capacity, both utility and non-utility units, plus the net of capacity purchases (imports) less sales

NERC-U.S. Figure 6



NERC-Canada Figure 7



(exports). To quantify the uncertainties that exist in the realization of the 1988-1997 planned capacity resources, a NERC survey was conducted on the likelihood of delays in the scheduled in-service dates of both utility and non-utility generator additions. Based on this survey, the effects of delays of planned capacity additions and anticipated reductions in existing capacity were developed as indicated in Figures 6 and 7 for the United States and Canada, respectively.

The likely reductions in existing generation facilities are due to a combination of refurbishment of some older units not being economically attractive and the effects of possible future environmental regulations. In the U.S., by 1997 an estimated 14,600 MW of coal-fired capacity (about 5% of the total coal-fired capacity) will likely be permanently lost to service as a consequence of currently anticipated acid rain legislation.

By the end of the forecast period, delays of new capacity could reduce U.S. planned capacity resources from about 727,700 MW to about 721,500 MW. Possible reductions in existing capacity could cause a reduction of another 18,200 MW resulting in 1997 capacity resources of about 703,300 MW. Similarly, the planned capacity resources of 100,800 MW in Canada could be reduced by approximately 2,400 MW due to delays of new capacity and by another 1,500 MW due to early retirements of existing capacity, resulting in 1997/98 available capacity resources of about 96,900 MW. These scenarios regarding total planned capacity resources are compared with the peak demand forecast probability bandwidths to assess the reliability of future electric supply.

Capacity Resources Adequacy

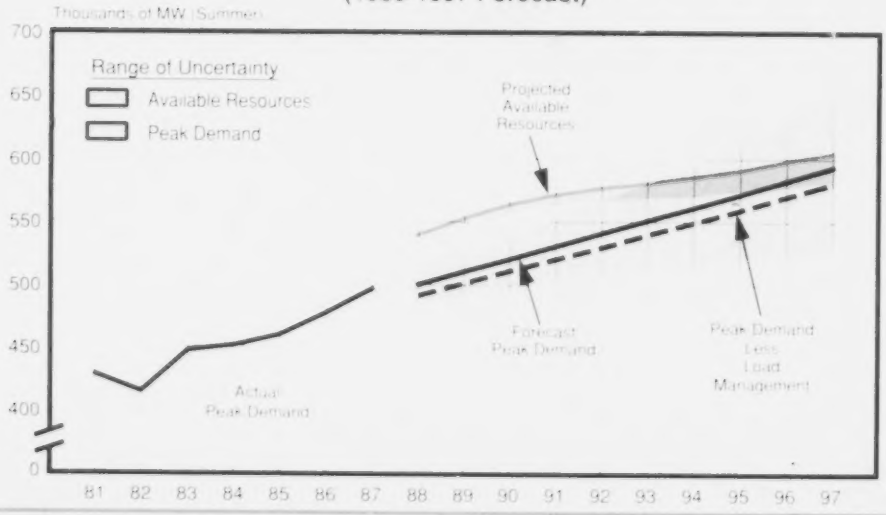
Historical generation performance data indicates that a portion of the installed capacity is unavailable at the time of peak demand due to outages, seasonal deratings, and in some cases maintenance requirements. Therefore, the planned capacity resources indicated in Figures 6 and 7 have been reduced to reflect the typical availability of generation during peak demand periods. This is shown in Figures 8 and 9 as the line labeled "Projected Available Resources." The projected available resources line provides an indication of the capacity that can be expected to be available to supply the peak demand if the planned capacity resources are placed in service on schedule. For the United States, the projected available resources line reflects that, on average, about 17% of the planned capacity resources is not expected to be available to supply the peak demand. For Canada, the corresponding amount is about 10%, reflecting a greater proportion of hydroelectric generating capacity which has a higher average availability.

Recent actual and projected peak demands are also shown in Figures 8 and 9 for the United States and Canada, respectively. The range of uncertainty associated with the forecast peak demand is also indicated on each of these diagrams and is the same as shown in Figure 2 (U.S.) and Figure 3 (Canada) in the chapter titled "Peak Demand and Energy."

NERC-U.S.

Figure 8

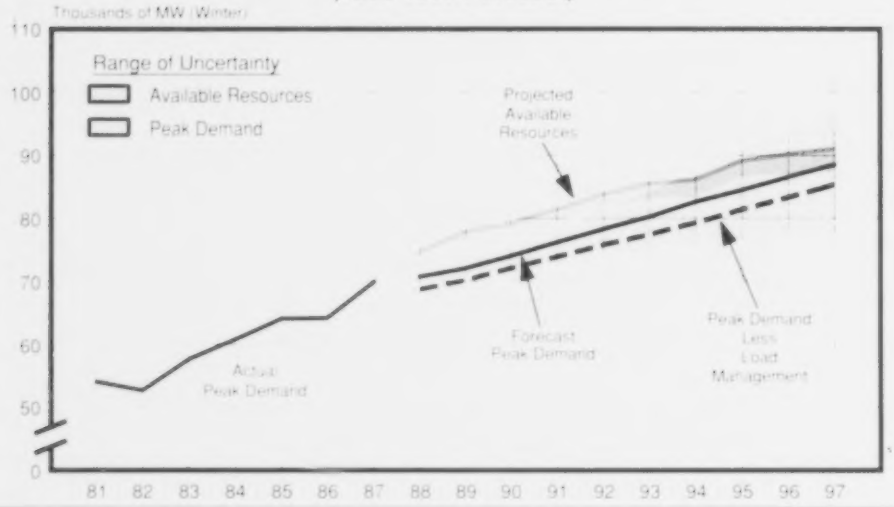
Ranges of Uncertainty for Peak Demand and Projected Available Resources (1988-1997 Forecast)



NERC-Canada

Figure 9

Ranges of Uncertainty for Peak Demand and Projected Available Resources (1988-1997 Forecast)



Figures 8 and 9 compare the projected available capacity resources with the forecast peak demands for the United States and Canada, respectively. These figures show that the available resources, as planned, are adequate to supply the base peak demands in both the United States and Canada throughout the next decade. However, the risk of a capacity shortfall does exist.

There is a 50% chance that actual demand will exceed the base peak demand projections, and a 10% chance that actual demand will exceed the upper demand bound. Should the latter occur, demand could exceed projected available resources by 1994 in the United States and by 1993 if the lower bound of resource availability were also to occur. Similarly, the upper demand bound could exceed projected available resources in Canada by the winter of 1994/95, or 1993/94 if the lower bound of resource availability were to occur. The peak demands and their associated ranges of uncertainty include weather effects on a statistical basis, averaged over time. Weather extremes (hot summers in the United States or severe winters in Canada) could cause demand to exceed available capacity earlier than would otherwise be projected.

The planning of generation capacity is not static. It is a dynamic activity. Supply plans are modified with changing demand forecasts. Therefore, the occurrence of the higher bound of the demand forecast without a change in planned capacity resources is not likely. However, there is a risk that higher load growth could occur so rapidly that utilities would be hard-pressed to provide adequate capacity due to the long lead times associated with new capacity additions.

There is concern that, even if the base peak demands are realized, the projected available resources may be insufficient to serve them toward the end of the forecast period. This is the case in the United States as the lower bound of the range of resources uncertainty intersects the base peak demand line in Figure 8 toward the end of the assessment period. In considering this, it must be recognized that peak demand may not be reliably served even if the total available generation exactly matches the projected demand since utilities are required at all times to maintain an additional amount of generation capacity in operation (typically in the order of 3% of demand) ready to respond immediately to demand variations and generation system control requirements.

Based on these considerations, it appears that the ability to supply the base peak demand in the United States may be questionable by the middle of the 1990s. Use of load management to the maximum extent projected would decrease peak demand as shown in Figure 8 but would not solve this critical condition. On the other hand, Canada should have sufficient generation at the end of the forecast period even if the postulated capacity addition delays and loss of existing capacity should occur. However, some use of load management would likely be required at the end of the period.

The projections included in Figures 8 and 9 apply to the composite peak demand and capacity resources of the United States and Canada and therefore cannot be inferred to reflect the situation in any Regional Council, utility, or group of systems in either country. Some Regions or utilities may experience critical capacity situations earlier than these national figures would indicate.

Capacity Resources Concerns

Capacity plans are developed to supply the most likely projected loads and are modified as the load forecast changes. However, those capacity plans are subject to uncertainties, and the ability of the utilities to address these uncertainties determines how well they will meet their obligation to serve customer load reliably.

The loss of existing capacity, primarily due to possible environmental regulations, is difficult to address. No one knows if and when such regulations will become reality, how soon they will become effective, which portion of the capacity will be affected or lost, nor whether sufficient time will exist to plan and build the necessary facilities to replace the capacity that will be made unavailable. It may be that the utilities will need to rely on NUGs to an even greater extent in order to acquire sufficient capacity in a short period of time.

If a trend toward higher growth should begin, prompt recognition of the trend will be essential to initiate an adequate response. Since one or two years of higher than forecast peak demands may be caused by temporary conditions, several years may be required to identify a new trend in the peak demand growth rate. Once an increase in growth rate is identified, it may be too late to install baseload generation in time, as typical baseload capacity lead times are 10 to 12 years. Utilities may be limited to short lead time generation options to provide adequate capacity, and even these require approximately three years lead time.

Reliance upon short lead time options by many utilities could cause a situation in which many orders for equipment would require delivery at approximately the same time. This could exceed the capabilities of the equipment manufacturers to produce this needed equipment and result in some utilities seeking to rely on the resources of their neighbors. The neighbors, in turn, may be in the same situation and may not be in a position to provide sufficient assistance.

Load Management

Load management is a tool that is being used by many utilities to reduce peak demand and delay generating capacity additions. Forecasts indicate that the equivalent of about 2.2% of the peak demand in the United States and 3.6% in Canada will be under load management by 1997. The associated peak demand reductions projected to be available from load management programs are illustrated on Figures 8 and 9 for the United States and Canada, respectively.

The benefits of load management to a utility and the amount of customer load that can be reliably and cost-effectively managed tend to be unique to each utility system. Some of the factors which significantly influence the benefits of load management are:

- the variation of the customer's peak demand with time on a daily, weekly, seasonal, and annual basis
- the overall characteristics of utility system peak demand and resources
- the margin of a utility's capacity resources over its peak demand
- the timing and cost of new capacity resources and of implementation of the load management programs
- the costs and availability of competing fuels for electric generation.

There are also certain drawbacks and uncertainties associated with dependence upon load management as a tool to delay capacity additions. A key uncertainty is customer acceptance. Utility experiments and pilot programs have so far led to inconsistent results regarding customer acceptance. The danger is that customers who initially participate in load management programs because of the financial incentives may decide, once the electric supply to their equipment has actually been interrupted a number of times, that the inconvenience of these interruptions outweighs the cost savings and withdraw from the programs. Such actions, particularly if taken by commercial and industrial customers, could result in unanticipated increases in utility peak demand which must be served at a time when capacity supply may already be critical.

Load management cannot be considered as a resource on the same basis as generating capacity. Depending on the usage patterns of the managed loads, the MW value of load management may be less during off-peak periods than at peak demand times. A generating unit, on the other hand, can always provide essentially the same number of megawatts. Because load management is a demand reducer rather than a generating source, it has several operating features that may tend to lower total system reliability. For example, utilities may be unwilling or unable, due to contractual or regulatory restrictions, to use load management to help a neighboring system that is short of capacity whereas available generating capacity would be used for that purpose.

More important, there is substantial uncertainty as to how much actual load reduction will be realized at the particular time it is needed. Inconsistent load response has already been observed in experimental and pilot load management programs. Industrial and agricultural subscribers may also insist on the capability to override the utility load management interruptions.

Load management has many potential advantages, but it also has many potential drawbacks. The relative weight of each is still uncertain.

Electrical Energy Production and Fuel Supplies

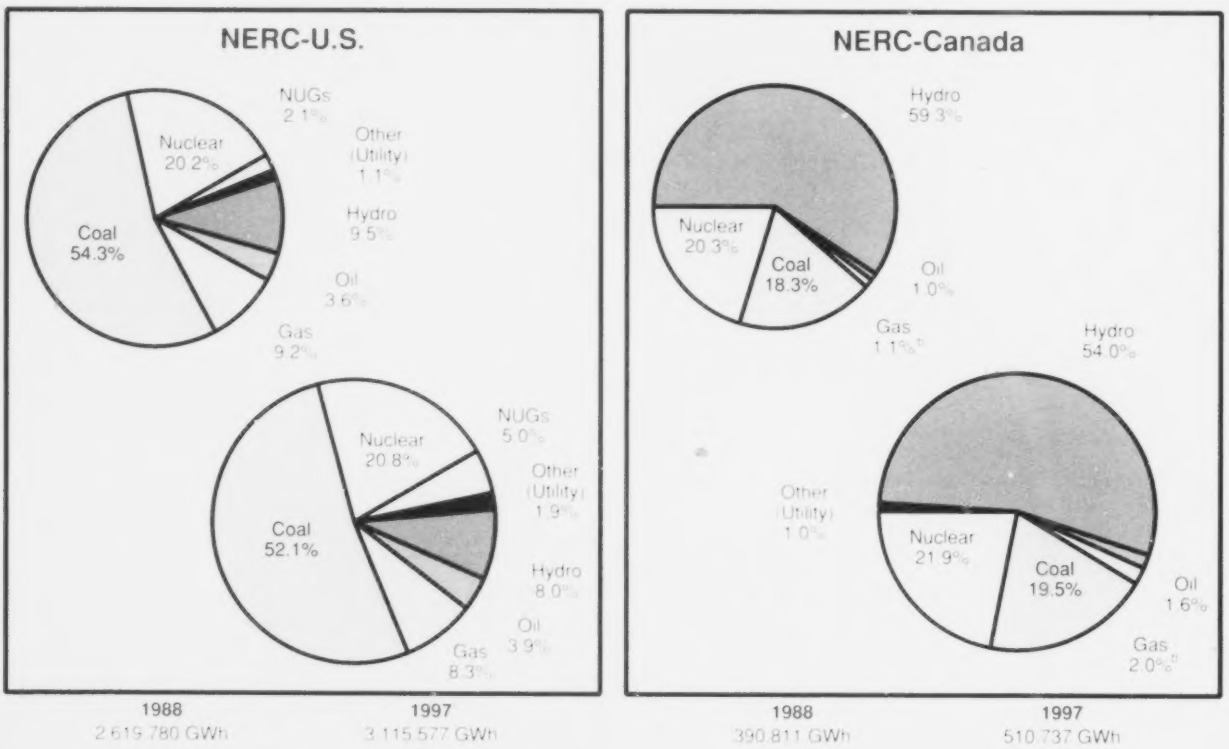
The electrical energy produced from primary energy sources (pumped storage generation and net imports excluded) is projected to increase from 2,620 to 3,116 million MWh in the United States over the forecast period. Similarly, electrical energy production over the same period will increase from 391 to 511 million MWh in Canada. The mix of fuels expected to be used to generate this electrical energy is illustrated in Figure 10. The U.S. and Canadian installed generating capacities in 1988 and 1997, also segregated by fuel type, are shown in Figure 11.

Over the next few years, the completion of nuclear units already under construction will dominate capacity additions in the United States and Canada. However, in the United States in 1988, coal-fired capacity is projected to provide about 54.3% of utility-generated electrical energy and coal is expected to retain its more than 50% share of annual electrical energy production in the United States through 1997. Hydro will be the mainstay of electrical energy production in Canada over the 1988-1997 period.

Electrical energy from nuclear capacity in both the United States and Canada is expected to increase over the next ten years. The total electrical energy produced from utility-owned oil- and gas-fired units in the United States will decrease on a percentage basis but will increase slightly in magnitude over the forecast period. In Canada, oil- and gas-fired capacity will increase on both a percentage and absolute magnitude basis.

Figure 10

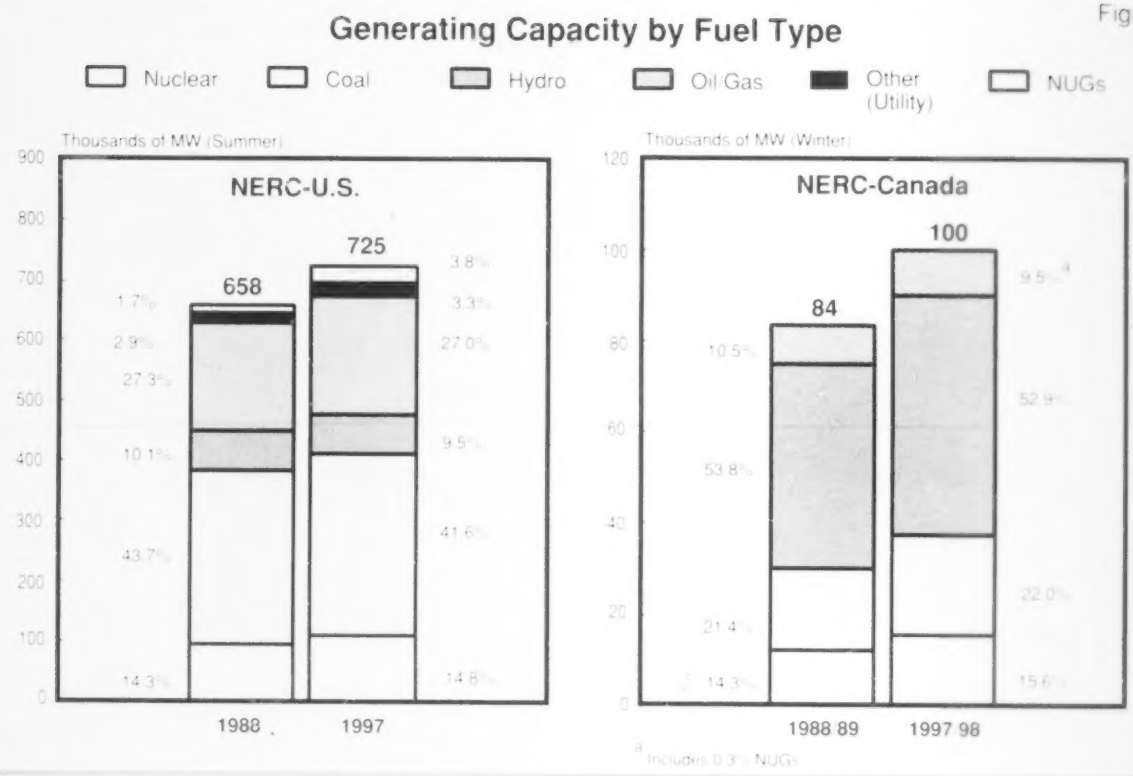
Electrical Energy Production[a] by Fuel Type



[a] Electrical energy from pumped storage generation and net imports excluded.

[b] Gas includes coal in 1988 and 1997.

Figure 11



Electrical energy production from non-utility generators is estimated to increase in the United States from 2.1% of total production in 1988 to 5% by the end of the assessment period and from 0.1% to 0.4% in Canada over the same period. A variety of fuels will be used to produce electricity from NUG capacity but natural gas is expected to be the predominant fuel.

Since the end of 1985, utilities have enjoyed abundant supplies and lower prices for coal, natural gas, and fuel oil. The drop in world oil prices early in 1986 resulted in a significant increase in the use of oil for electricity production. As usage of oil and gas has grown, so has concern over the continued availability of supply of these fuels. As history has shown, Mideast politics, oil embargos, or controlled pricing can result in unexpected demands for and shortages of future domestic fuel supplies.

Many utility customers are currently benefiting from savings due to the depressed prices of gas and oil. However, the continuation of these low prices keeps drilling activities at a minimal level, causes marginal domestic wells to be shut down, and reduces existing supplies with little restoration of oil and gas reserves for the future. The rate at which additional gas reserves are being discovered continues at a much lower rate than the production and use of natural gas. If this trend continues, it can be reasonably expected that the price of natural gas will escalate rapidly and supply disruptions will occur as gas reserves fall short.

In Regions where gas-fired cogeneration is displacing solid fuels, there will likely be an overall increase in gas consumption caused by cogeneration activities. As the surplus of natural gas declines, dependence on foreign oil is expected to increase as dual fuel generation is converted from gas to oil.

Concern is also being expressed over the fact that much of the use of natural gas by cogenerators and other non-utility generator facilities is not being reported by utilities in their forecasted fuel requirements for future years. Therefore, the total picture for gas usage in electricity production may be unavailable.

Assessment of Transmission Reliability

Planned Transmission System Additions

The bulk transmission systems, 230 kV and above, have proven to be valuable resources by enhancing reliability and providing the capability for firm and economy interchange. The role of the transmission systems will expand in the next ten years as utilities increase their dependence on remote generation sources, capacity purchases and sales, and economy energy transfers. Additions to the transmission systems will be needed in many Regions so that adequate reliability is maintained while accommodating utility system growth and expanded transmission use.

At the end of 1987, the bulk transmission systems of NERC consisted of 180,549 circuit miles of ac transmission lines and 3,527 circuit miles of dc transmission lines. New transmission planned for NERC over the next ten years includes 17,201 miles of ac and 1,448 miles of dc circuits. Additions for the United States and Canada are shown in Figures 12 and 13, respectively. There is a continuing trend in recent U.S. ten-year forecasts for fewer transmission additions. This trend is partially attributable to fewer new baseload generating unit additions, accepted heavier loadings on the existing systems, impediments to right-of-way acquisition, and the approvals process. This decreasing trend is not consistent with regulatory pressures to provide mandatory access by non-utility generators to electric utility transmission systems which may already be loaded to their capacity limits for reliable operation.

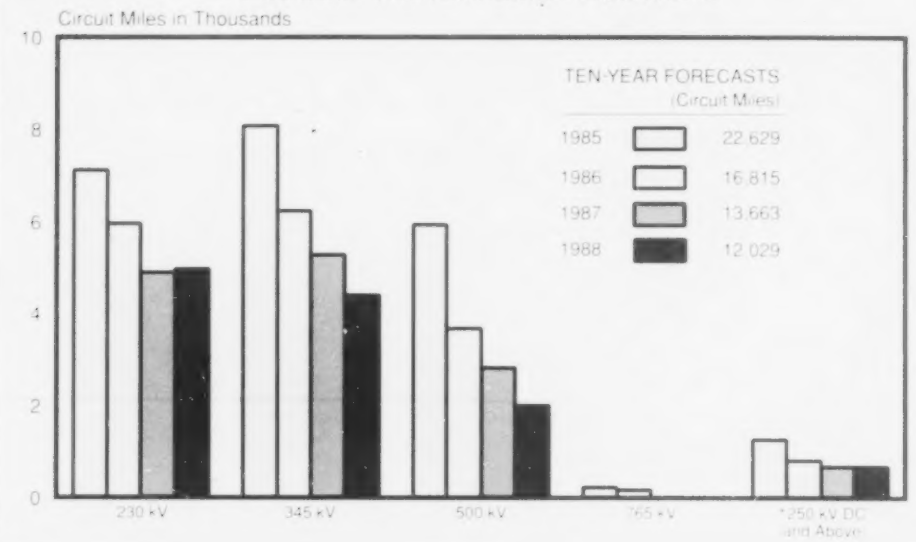
The approvals process continues to be a major threat to implementing plans for transmission additions. Examples of key transmission reinforcements impacted by delays are:

- The Baltimore-Washington 500 kV Loop – Completion of the 500 kV loop around the Washington, D.C. metropolitan area, originally scheduled for the mid-1970s, is now expected in the early 1990s. The two segments remaining for completion are the Chalk Point-Calvert Cliffs circuit and the Brighton-Waugh Chapel circuit.

  During recent zoning hearings, the issue of health effects of EHV lines has surfaced. The Maryland Public Service Commission has reopened the certification proceedings limiting the scope to consideration of safety and health effects, if any, associated with electromagnetic fields resulting from the operation of the proposed 500 kV lines. Further delay of the loop will reduce the reliability of the MAAC Region and neighboring Regions by limiting interregional transfer capability and reducing electric system stability margins in the Baltimore-Washington, D.C. area.

- The Second Belle River-Jewell 345 kV Line – This 22-mile line in Michigan is necessary to deliver electric power from the Belle River power plant to system load centers. Condemnation and zoning issues which had delayed construction are now resolved. The line is currently under construction with completion expected before the summer of 1989. Without this line, restrictions on transfers from Ontario Hydro to Michigan are required during certain circuit outages and adverse weather conditions.

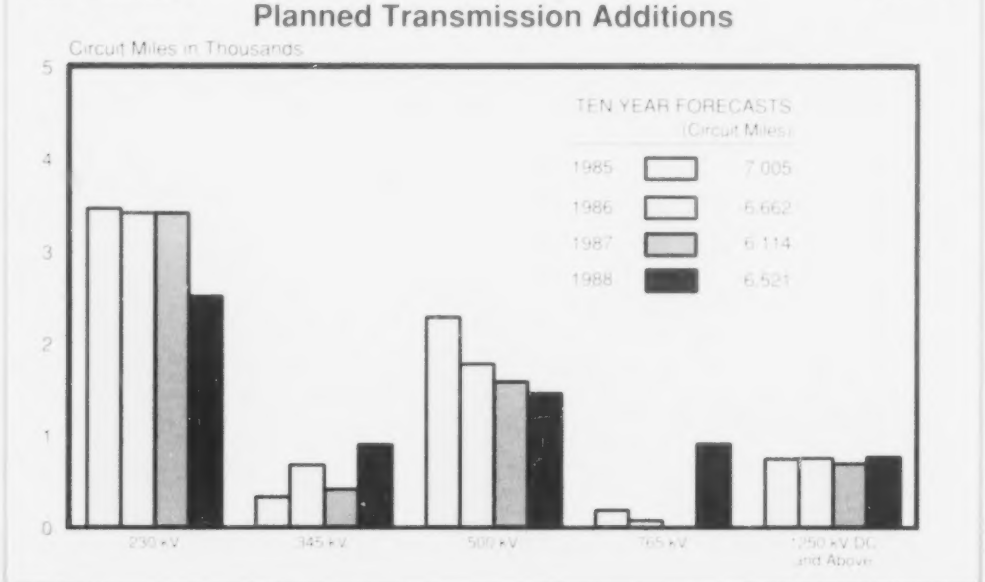
NERC-U.S. Figure 12



- Southwestern Ontario 500 kV Transmission – Extensive regulatory delays have impeded the completion of 500 kV reinforcements in southwestern Ontario connecting the Bruce nuclear generating complex with Ontario Hydro's 500 kV network. Final approvals were obtained in 1987, and the lines are currently under construction. The double circuit 500 kV line from Bruce to the London area is now expected by August 1990 and the single circuit 500 kV line from the Nanticoke generating station to the London area by August 1991.

  These lines are needed to incorporate the full output of the Bruce nuclear complex into the system, to provide a reliable supply to customer loads in southwestern Ontario, and to maintain transfer capability between Ontario and Michigan. The delays in this transmission necessitated the installation of complex special protec-

NERC-Canada Figure 13



Functions of Transmission Systems

tion systems to minimize the cost penalties associated with transmission constrained nuclear capacity. Completion of these circuits is the only way to eliminate the capacity constraint, the high-cost generation penalties, and the associated complex special protection systems, thereby enhancing the reliability of supply to this portion of the province.

- City of Austin 345 kV Lines – In September 1987, the Austin City Council voted to cancel the 345 kV lines previously planned for service in 1988 for the Austin area. It cited cost, need, and environmental impact considerations as motivations for the cancellation, which was ordered against the recommendation of the Austin Electric Utility Department. This action has resulted in recent plan revisions which attempt to replace all canceled 345 kV facilities with 138 kV facilities. These replacements, however, do not enable Austin to continue to meet either ERCOT planning criteria or NERC planning guides.

- Salem-Zenith 345 kV Line – Application for certification of the 55-mile, double circuit, 345 kV Salem-Zenith line in Texas, which has been in the regulatory certification process for over four years, was rejected by the Texas Public Utility Commission (PUC) in November 1986. This line is needed to increase emergency transfer capability within ERCOT, to deliver energy from remote generation, and to provide for economy energy and firm capacity transfers. An appeal of the PUC decision resulted in a December 1987 ruling by a State District Court which ordered the Texas PUC to reexamine the findings of fact in the case. Intervenors have now appealed the District Court ruling.

- Lake Tarpon-Kathleen 500 kV Line – Construction of this line in Florida has been delayed because of a state-initiated review of electromagnetic field effects. The line, which was originally proposed for December 1987, is now projected for service in early to mid-1991. Until the line is placed in service, higher cost local generation will have to be operated to maintain system reliability. As area load increases in the early 1990s, uneconomic operation of local generation will become ineffective in maintaining reliability.

Adequacy of Transmission Systems

Regions continually evaluate the ability of their internal transmission systems and interconnections to meet the objectives, including those for transfer capability, specified in their individual reliability criteria. These assessments are made on both short- and long-term bases. To complete these evaluations, Regions also participate in joint studies with adjacent Regions. These interregional and intraregional studies measure overall system strength or capability which is used to judge future transmission system adequacy.

As currently planned, bulk electric transmission systems throughout NERC are generally expected to be adequate during the next ten years. However, reliability deficiencies exist in some areas where transmission facilities have not been constructed as planned or where the use of the transmission system is changed from that planned. Spe-

Transmission System Transfer Capability

cific areas of adequacy concerns are highlighted in the ERCOT, MAAC, NPCC, and SERC regional sections.

Transmission Reliability Concerns

The future adequacy of the electric transmission systems will depend on the ability of the utilities to implement planned transmission reinforcements and improve operating methods and tools. These enhancements will allow maximum utilization of transmission capacity with sufficient control so that reliability is not significantly affected.

Some of the major concerns that impact transmission system reliability include:

- Heavy Transmission Loadings – Heavy transmission loadings continue in many areas throughout NERC. Examples of this in two Regions, MAAC and NPCC, are illustrated in Figures 14 and 15, respectively. Over 90% utilization of the MAAC transmission systems during the 1981-1987 period is shown in Figure 14. MAAC defines utilization as a measure of how close its transmission systems were operated to the transmission limit that was most restrictive in each hour of the year. For NPCC, Figure 15 illustrates the loading on one of several major interfaces in the New York Power Pool (NYPP). This interface represents a number of high voltage transmission lines which connect eastern New York state and New England to systems to the West. Figure 15 shows the percent of time during 1987 that loading was equal to or greater than a given percentage of the interface capability. This interface is not loaded near 100% of its capability all of the time because of changes in economic generation dispatch, variations in customer demand, and restrictions on other transmission lines or interfaces.

  There are several factors that contribute to heavy transmission loadings. Transmission systems are used to deliver remote generation to load centers, for daily economy energy transactions, and for long-term capacity and energy transactions. Parallel path (or loop) flows resulting from transactions in neighboring systems also contribute to heavy transmission loadings. Parallel path flows become a problem when they place a burden on

Figure 14

MAAC Transmission Utilization
1981-1987

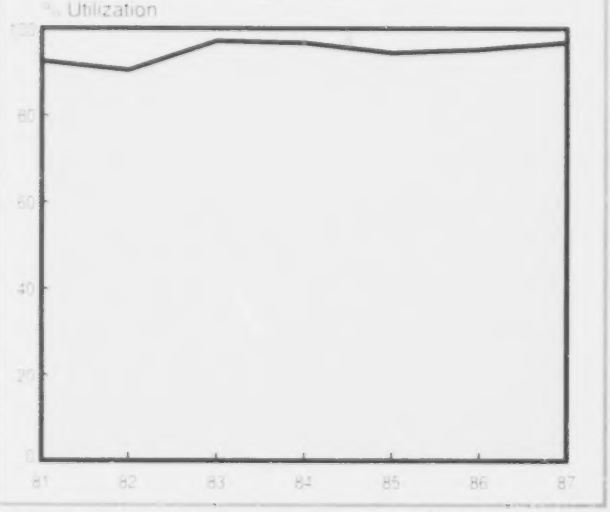
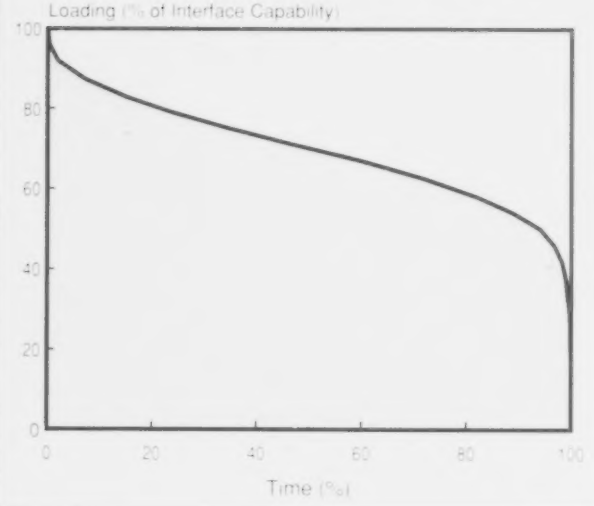


Figure 15

NYPP Transmission Utilization
1987 Interface Transfer Flows



the utility owning the transmission system which is being used by others. The economic incentives for short- and long-term energy and capacity transactions are expected to continue. In addition, the scope for use of transmission systems is being expanded by regulation to include use by non-utility generation. It is expected that the combination of all these uses will result in continued heavy transmission loadings in many areas of NERC.

- Consequences of Unexpected Facility Outages – Heavy transmission loadings affect reliability because they increase exposure to potentially severe consequences should unexpected facility outages occur. Systems are being operated within the same accepted reliability standards as before, but at or near their transmission capacity limits for longer periods of time. This increases the likelihood of severe consequences resulting from equipment failure. It is as if someone is walking near the edge of a cliff. Occasionally, they will trip and fall. When they are a distance from the edge, a fall may be relatively harmless. Near the edge, however, a fall can be fatal. The more time spent walking near the edge, the greater the chance that a trip and fall will be disastrous.

- Difficulty in Scheduling Maintenance and Tests – Heavy loadings on transmission systems affect reliability in another way by limiting the removal of facilities from service to perform maintenance and testing. If proper maintenance is not permitted, performance of equipment can be degraded resulting in more frequent forced outages or improper operation. When transmission lines are out of service for maintenance, the remaining system components can be stressed even more, increasing the risk of major system disturbances.

Measures to Minimize Impact of System Disturbances

Failures of system components that cause system disturbances do occur even though sound planning and operating criteria are followed. It is not feasible to plan, design, and operate a system that is completely fail-safe for multiple equipment outages or contingencies. However, measures are taken to minimize the impact of severe disturbances so as to preserve as much of the electric system as possible and to restore electric supply to the affected areas as rapidly as possible. When major disturbances occur, they are thoroughly analyzed to identify and understand the contributing factors. Lessons learned from these investigations are applied to help minimize the likelihood of future similar disturbances.

Documents such as the annual NERC "System Disturbances" report are made available to all Regions and utilities so system improvements can be made and similar problems avoided in the future. Protective relay systems are a good example of this process. Improper operation of protective relays has been identified as one of several factors contributing to the frequency and severity of system disturbances throughout NERC. Electric utilities continue to intensify their efforts to analyze and correct cases of relay misoperation.

Protective Relaying

Increased Operating Complexity

Utilities are actively pursuing ways to better deal with the increasing complexity of operating the electric systems. Improvements in system monitoring, data exchange, communication of plans and procedures, on-line security analysis, joint planning and operating studies, and operator training are some of the many areas continuing to be addressed in an effort to adapt to the changing nature and growth of the electric systems while maintaining adequate reliability.

The complexity of operating transmission systems is increasing as these systems are used more extensively for interregional and intraregional transfers. In some instances, complexity is increased through the use of special protection systems or remedial action schemes. Complexity in operations can have an adverse effect on reliability because it becomes more difficult to analyze and control the systems and to schedule transactions while staying within reliable operating limits. Some operating complexities of particular concern include the following:

- Parallel Path (or Loop) Flows – Because of the nature of ac transmission systems, energy transactions between two systems cause parallel path flows in other interconnected systems not directly involved in the transactions. These flows make it difficult to analyze system capability and performance because the sources of these transactions are not easily determined. The wide range of transaction possibilities creates a myriad of conditions to study, monitor, and control.
- Voltage and Stability Limits – Voltage and stability limits become more significant as electricity is transferred over greater distances, and they also become more difficult to monitor and control. For example, with a stressed or heavily loaded transmission system, voltages may be well within acceptable limits for normal conditions; however, a single facility outage or contingency due to equipment failure or misoperation could cause immediate excessive and widespread reduced system voltages. To make the situation worse, the critical facility failure or misoperation could be remote from the utility that would experience the largest voltage decrease. This type of situation could go unrecognized until after the contingency occurs if there is inadequate monitoring and communication among utilities. Coordination in planning and operating the electric systems is vital to maintaining adequate system reliability when long distance electricity transfers are common. Voltage problems are especially critical because system operators may not have time to make adjustments before a system collapse occurs.
- Increased Communications and Control – When system limits are approached or exceeded, the operator must make adjustments to maintain or reestablish reliable conditions. The operator must deal with many concerns, such as contract terms, economic impacts, emergency capability of facilities, and transmission loadings, when making the necessary system adjustments. The many different transactions and their interactions increase the importance of good communications for monitoring, evaluating, selecting, and implementing proper system adjustments.

Special Protection Systems

Aging of Transmission Facilities

Aging transmission line and substation equipment can adversely affect transmission system reliability. As equipment ages, repair parts are more difficult to acquire or can take a long time to manufacture. The extended repair times for older equipment create increased exposure to multiple facility outages as well as an additional layer of complexity for the system operator. These conditions can result in unusual system performance and in disturbances that may be more frequent and more severe than normally expected.

Utilities are dealing with this aging problem in several ways to minimize the effects on reliability. Spare equipment is provided for critical facilities. Some utilities are partners in programs that provide equipment for emergency assistance to one another. Systems are monitored and operated within limits that recognize the effects of the outages of critical components. Other utilities have started work which will provide a better insight into the exact nature of the aging effects on various transmission system components. This information will enable utilities to assess the seriousness of aging and to select candidate facilities for refurbishment in a logical sequence.

Reliability Issues

Economy Versus Reliability

Economy-Reliability Balance

Many factors must be considered when planning and operating an electric system. Among the more important factors are economy and reliability. Both utilities and regulators play an important role in evaluating and assessing these factors. Since these factors typically work in opposition to one another, it is important that economy and reliability are properly balanced using consistent and objective evaluation criteria. This balance is particularly delicate and many times achieving what seems to be the best balance in the short term may in fact produce inefficiencies and inadequate reliability in the long term.

The following examples help to illustrate some of the important issues in which maintaining the balance between economy and reliability is of concern.

- Operating Closer to System Limits – With the technology now available to utility planners and operators, electric systems are able to operate closer than ever to the edge of their technical capabilities. Operating in this fashion can result in substantial economic benefits for both the utility and its customers. While improved control and monitoring technology have made it easier to measure how close the system is to its limits, other factors work to complicate the operation of the system and force it toward those limits.

  Operating an electric system at the limit of its capabilities exposes that system's customers to a greater risk of widespread service interruption. The consequences of a misoperation or equipment failure are often more severe the closer a system is operated to its limits. A combination of two or three simultaneous equipment outages may not cause a major problem for a system which is being operated with an adequate or more than adequate margin of capability, but the same outages may have catastrophic results when the system is heavily loaded and has limited margins. With modern society's dependence on a reliable electric supply, the consequences of a widespread service interruption can be staggering from both an economical and societal standpoint. When assessing the economic benefits of operating a system closer to the limit of its capabilities, it is critical that the potential cost of inadequate reliability be carefully weighed.

- Economy Energy Transfers – Throughout the Regions, utilities strive to make optimal use of their existing transmission systems for economy energy transfers. Due to the cyclic nature of customer demands and the step increases in system capabilities normally produced by system improvements, a moderate amount of reserve transmission capability is often available. Utilities make efforts to put this reserve capability to use for the benefit of their customers by purchasing lower cost economy energy, when available. There is, however, a risk of depleting transmission capability which may be needed for system emergencies when transferring economy energy. Those responsible for balancing the reliability of the network against economical operation must ensure that use of the transmission network for economy transfers is not allowed to encroach on the primary purpose of interconnected system operations – reliability.

- Reduced Maintenance – Near-term economic pressures, generated both internally and externally, have mandated significant cutbacks in maintenance budgets and staffing at many utilities. These cutbacks may result in greater risk of equipment failures which could affect not only the utility owning the equipment and its customers, but also other interconnected systems. It often takes many years for the full effects of reduced or delayed maintenance to become apparent. Likewise, once increased equipment outages and inadequate reliability due to reduced maintenance appear, it often takes many years to restore reliable operation. It is important when evaluating the priorities on the allocation of limited financial and human resources that the long-term reliability and economic impacts be properly balanced.

- Capacity Purchases – The purchase of capacity from either utilities or non-utility generators in lieu of the construction of new generation facilities is often viewed as an option which offers substantial benefits to both buyer and seller. However, a capacity purchase does not add to the total capacity of an interconnected network. Rather, it simply transfers capacity responsibility to another party. In the course of evaluating the economic benefits of capacity purchases, buyers should be aware that over-dependency on capacity purchases may expose the purchasing utility to reliability prob-

lems. Such problems may be caused by a variety of reasons such as transmission system limitations, or the possibility that the seller may be unable to fulfill the contractual obligation to provide service to the buyer. The purchase of capacity from remote locations may also reduce transmission capability which would otherwise be available for system emergencies. Simply stated, the purchase of capacity places additional risks on the purchasing system. These risks must be carefully evaluated in determining the proper balance between the reliability and economic benefits of such purchases.

- Demand Management – At many utilities, the use of demand management, including both conservation and load management, has been found to offer potentially significant economic benefits. A megawatt of demand management is often considered to be a suitable replacement for a megawatt of additional generating capacity. A concern to many utility planners and operators is the fact that a megawatt of demand management is not equivalent to a megawatt of new generation.

  Unlike generation, demand management programs fail to provide reactive power for maintaining system voltage. Voltage collapse due to insufficient reactive supply is becoming a greater concern within the Regions, and can occur quickly without warning or time to respond.

  Many demand management programs involve load reductions which are only available during times of peak demand, or for just a few hours each year. On the other hand, a megawatt of generation is nearly always available to assist the owning utility or other interconnected utilities during emergency situations.

  Changes in customer attitude which can reverse the effectiveness of demand management programs at any time are also of concern. For example, while customers may readily purchase large quantities of interruptible service during periods when capacity margins are high, and service is interrupted rather infrequently, they may quickly decide to convert back to firm service if capacity margins become critical, and the number of interruptions increases. These types of considerations should not be overlooked when assessing the balance between the economic and reliability benefits of demand management.

- Remedial Measures – The use of remedial measures, such as special protective systems (or remedial action schemes) and complex operating procedures, as a means of deferring the construction of new transmission facilities often has economic benefit. However, utilities which are increasing their dependence on remedial measures should weigh carefully the impact of their complexity and the consequences of their misoperation. Typically, such remedial measures have significantly greater adverse consequences of failure than would result from the failure of a transmission facility component. The probability of misoperation and the severity of the consequences of misoperation are important aspects of assessing the balance between economy and reliability.

For each of the above concerns, the complexity of properly balancing economy and reliability is a difficult assignment. Utility planners and operators continue their efforts to identify out-of-balance situations and to encourage the understanding and support of regulators and their customers in restoring balance.

Reliability Issues

Public Policy Disincentives

Regulation

Electric utilities in the United States and Canada operate under an umbrella of regulation. Most major projects involving generating capacity, purchases of capacity, demand management programs, and bulk system transmission lines are subject to review and approval by various governmental agencies at the federal, state or provincial, and local levels. Simply stated, the purpose of regulation is to assure that:

- The needs of electric customers will be served in a reliable and environmentally benign manner.
- Electric utilities are able to recover their costs and attract the capital necessary to continue to satisfy the needs of electric customers.
- Electric rates for customers are kept as low as possible consistent with the first two requirements.

In recent years, however, the goal of low electric rates in the short term has increasingly taken precedence over the others – creating disincentives which adversely impact electric service reliability. If not corrected, this trend could lead to an unreliable electric supply in the future.

Disincentives brought about by recent public policy decisions have created an environment in which few utilities in the United States are willing to undertake the financial risks inherent in the commitment to a major generating capacity addition. Some of these disincentives may apply in the future to power purchase agreements, demand management, life extension programs, and non-utility generators. Among the public policy actions which have led to this situation are:

- Pressures to shut down plants (for example, the 809 MW Shoreham nuclear unit in New York)
- Prevention of plants completed and ready for service from going into operation (for example, the 1,150 MW Seabrook nuclear unit in New Hampshire)
- Disallowance or severe limitations on cost recovery for abandoned plants (for example, the 1,150 MW Callaway 2 nuclear unit in Missouri)
- Limitations on cost recovery even for plants completed and in service (for example, Montana Power Company's share of the 700 MW Colstrip 4 coal-fired unit in Montana)

Certain justifications for such regulatory actions seem to appear repeatedly: "prudency" reviews, "used and useful" criteria, determinations that units are not "reasonably necessary" for adequate and reliable electric service, and variations on these. While the words may be different, most come down to one thing – a focus on *need*, and a determination that the capacity addition is *not* needed based on *hindsight*.

"Hindsight" is the key. Determinations founded on after-the-fact observations ignore the uncertainty inherent in planning, financing, and constructing new generating capacity.

Planning Uncertainties

The lead time for large generating units is now in the 10- to 12-year range. This means that a utility must determine in 1988 if a major unit will be needed in the year 1998 or 2000. Ironically, current approval processes sometimes account for about half of that lead time. If lead time could be shortened, utilities would be able to defer unit commitment to a point in time much closer to the point of need – when the electrical requirements of their customers can be projected with far less uncertainty. Long lead times magnify the impact of uncertainty and factors beyond the control of utilities which are inherent in all demand forecasts.

Another trend which has created disincentives is the tendency to exclude from rate base any generating capacity

above some perceived minimum level. The appropriate "minimum" level of capacity required for reliability is often a matter of dispute. Even when there is a consensus on the appropriate minimum, disallowances of capacity in excess of that amount ignore the uncertainties of forecasting. These decisions create a powerful disincentive.

The actions discussed above create risks to utilities of such magnitude that they act as major disincentives to the construction of new capacity. They also have a detrimental effect on the availability of investment capital for other utility projects. A utility may find it difficult to finance the construction of needed transmission lines, or the expansion of its subtransmission and distribution system, because it has made financial commitments to generating units which face uncertain regulatory treatment. Even when financing is available, it may be only obtainable at a relatively high rate.

While the situation is not as severe as in the area of generating capacity, some utilities, such as San Diego Gas & Electric Company and Gulf States Utilities, have encountered regulatory disincentives for important transmission projects and for power purchases.

Other public policy actions, in addition to financial risk disincentives, are also adversely affecting the reliability of both generation and transmission electric supplies. A number of issues can be cited as examples of this trend.

- Inconsistent Public Policies – Inconsistent public policies make electric supply planning for the future unpredictable. Utilities must be able to anticipate with reasonable certainty what the regulatory and legislative requirements will be and how they will be applied.

  Consistent rulings on individual projects from initial authorization to completion and operation are critical. Changes or inconsistently applied policies cause delays and ultimately increase costs to electric customers, and lower reliability.

- Regulatory Delays – The regulatory process takes time. Allowance for this is included in utility planning. However, when the process is delayed and decisions are not rendered on a timely basis, society runs the risk that key facilities may not be in service when needed. In addition, costs to customers usually increase.

- Overlapping Jurisdiction – Major utility projects often require the approval of federal, state or provincial, and local agencies. When the findings of these agencies conflict, delays occur – leading to the risk of inadequate system reliability and higher cost.

  The Shoreham and Seabrook nuclear units are cases in point. Conflicts between state and federal governments (Shoreham) and between two states (Seabrook) have prevented these needed capacity resources, long completed, from operating.

- Least-Cost Planning – Utilities have always attempted to develop plans to reliably meet the needs of customers at the lowest possible cost. This is just common sense and good business practice. There is no fundamental disagreement between utilities and public policymakers on the philosophy of least-cost planning. However, if the application of least-cost principles does not adequately recognize the need for reliable generation and transmission systems, the end result could be inadequate electric supply and an electric system vulnerable to cascading facility outages and blackouts.

Utility Strategies

The general reaction of most utilities to these risks and disincentives is to adopt strategies to avoid capital expenditures for major projects, especially large generating units. Most utilities have shifted toward increased reliance on other options, such as:

- Life extension programs for older utility-owned generating units approaching retirement
- Capacity and energy purchases from other electric utilities
- Non-utility generators (cogenerators, small power producers, independent power producers, and others)
- Demand management programs
- Combustion turbines or other small units

Each of these options has a place in utility supply plans as well as a very real contribution to make, even though each has its own set of uncertainties. The point is that our industrialized, high technology society is so dependent on an adequate and reliable electric supply that *no* option should be dismissed out-of-hand, including large utility-owned generating units. In general, the future reliability of electric supply to society would best be served by expanding rather than limiting options – by maximizing rather than restricting flexibility.

Until recently, disincentives have almost exclusively been focused on utility-owned generating units. Hindsight decisions are now also being applied to capacity purchase agreements, contracts with non-utility generators, demand management programs, and other strategies.

Preserving Flexibility for the Future

To restore and maintain flexibility in dealing with future electricity requirements, it is imperative that a partnership of electric utilities and public policymakers be formed to

initiate changes in the regulatory process. Needed changes include:

- Recognition that the economic and social factors which drive electricity demand can and will change, and hence the growth in electric demand will change over time. No forecasting methodology can precisely identify future electricity requirements.
- Consideration of forecast uncertainty when evaluating so-called "surplus capacity" situations. For one thing, surpluses can evaporate very quickly just through normal growth in electric demand. Secondly, to take advantage of the economies of scale, it is often more economic to implement a large block of capacity somewhat in advance of need to cover demand increases over a number of years, even though capacity may exceed the minimum requirement for a few years.
- Recognition of the need to link the operation and cost recovery, once a unit or other project is made available for service, to the initial agreement between the utility and public policymakers regarding need. If a proposed unit, contract, or program has been licensed or otherwise approved by the appropriate agencies, operation and legitimate cost recovery should not be prevented by hindsight appraisal of need.
- Reduction of project lead times. Utilities, public policymakers, and customers would benefit if lead times could be shortened. The risk of having either too much or too little capacity would be significantly reduced if the decision point for capacity commitment were closer to the actual point of need.
- Recognition of the uncertainties and limitations of the various means of satisfying demand – particularly non-utility generation and demand management. The long-term availability of these options depends on factors which utilities may not be able to control. Over-dependence on such options could place future reliability at considerable risk.
- Consideration of the technical characteristics and limitations of bulk electric systems by all parties. Electric systems perform in accordance with certain precise physical laws which no amount of legislation or regulation can change.

The situation regarding adequacy of supply is growing serious in some areas of the United States. Now is the time to form a partnership and take corrective actions.

Reliability Issues

Transmission Access and Deregulation

Transmission access and deregulation are forces which potentially threaten future electric system reliability by increasing transmission system loadings, reducing transmission capability margins, and increasing coordination problems. Transmission systems were not designed for unlimited transmission access. It is imperative that any future transmission system access policies recognize the need to maintain adequate electric system reliability.

Transmission Access

In today's evolving era of deregulation, competition, and transmission access, there are ever mounting economic pressures to operate electric systems to achieve greater cost savings. Suppliers of higher cost electricity are increasingly motivated to curtail expensive generation, replacing it with lower cost generation purchased from other suppliers. Moreover, large customers served by utilities with comparatively high rates, often the result of geographical location, seek access to the interconnected transmission network to obtain electricity from lower cost suppliers.

The transmission network provides the link between buyers and sellers in accommodating electricity exchanges. By and large, the electric transmission systems are owned and operated by electric utilities and are critical to providing reliable electric service. They were not designed to accommodate the concept of unlimited transmission access.

Transmission access is a term used to describe the concept of making a utility's transmission lines available to other utilities and non-utilities for buying and selling electricity. Accessibility to the transmission system or "transmission access" by a large number of entities, which have had limited or no access in the past, poses a potential threat to future electric system reliability. The degree of transmission system access has not been clearly defined and could foreseeably range from the way in which the electric utility industry is operated today to an entirely open access policy for any entity involved in buying and selling electricity.

The degree to which a supplier has access to the transmission network helps to determine the supplier's level of competitiveness with other suppliers. There is growing pressure to stimulate increased competition through deregulation and increased transmission access which may simply increase costs to some customers while decreasing costs to others.

Potential Reliability Effects

Unfortunately, operation of electric utility systems cannot be driven solely by economic considerations. Reliability is an essential consideration. Frequently reliability and economics work in opposite directions. Operating efficiency and prudent resource management are long-standing goals of the electric utility industry. In concert with these goals, electric utilities are ever mindful of their responsibility to provide adequate and reliable facilities to ensure that electric supply does not fall short in meeting their customers' demands for electricity. Under the deregulation concept, conflict over who derives the benefits from existing and new generation and transmission facilities will hinder the planning process as well as day-to-day system operations.

The major reliability implications of transmission access and deregulation include:

- Increased Transmission System Stress – As more and more entities attempt to use the transmission systems, there will be an increasing tendency to operate the systems near maximum capability for longer periods of time. The increased risk of exposure to transmission outages caused by uncontrollable events such as severe storms, fires, equipment failure, and other incidents especially when the transmission systems are heavily loaded is a serious concern.

- Reduced Transmission Capability Margins – The capability of the transmission system, or the maximum amount of electricity that the system is capable of reliably carrying, is a function of numerous technical constraints. Transmission capability is generally determined from computer simulations representing assumptions regarding the operating conditions which are expected to exist at a given instant in time. Increased transmission access and the impetus of deregulation and competition will naturally tend to drive transmission loadings higher for longer periods of time, squeezing existing system margins. The reduction or elimination of transmission margins may lessen the ability of the

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transmission network to accommodate heavy transfers of electricity under emergency conditions, and as a result reliability will suffer.

- Increased Coordination Problems – As an increasing number of transmission system elements are stressed over extended periods of time, simultaneous transfer limits will be encountered more frequently posing serious coordination and control problems. It may be virtually impossible to identify those transactions which are creating transmission loading problems at any given time. Increased operating complexity will place greater demands on operating personnel, and should an operator error occur, the consequences could very likely include widespread interruption of customer service. Increased competition resulting from deregulation may lead to reduced cooperation and communications which are vitally important in maintaining electric system reliability.

- Increased Parallel Path (or Loop) Flow Problems – Electricity does not flow entirely over the transmission lines defined by the contracts between buying and selling entities. Some of the contracted flow will also follow parallel transmission paths through systems which are not participants in the contract. To avoid transmission overloads resulting from excessive parallel path flows, third parties will lose the ability to use their transmission systems for their own purposes such as economy and emergency transfers. In addition, the parallel path flows may cause increased losses in the systems not party to the contracts. Increases in the number of contract transfers from increased transmission access will exacerbate the parallel path flow problem.

- Inadequate Transmission Facilities – Additional transmission lines will not be constructed to keep pace with increasing utilization unless adequate compensation is provided in exchange for use of the transmission systems by those entities receiving access. The inability to reinforce the transmission systems to accommodate increased use will result in degradation of electri system reliability.

Actions Needed

With the increased interest in transmission access and deregulation, a number of key reliability issues as outlined below must be resolved prior to adopting any transmission access policy.

- Priorities must be recognized in determining which entities will have access to the utility-owned transmission systems.

- Procedures must be established to identify the effects on the transmission network of electricity transfers between buyers and sellers to ensure that adequate transmission capability exists to accommodate such transfers. Parallel path flow problems will increase in magnitude and complexity in proportion to the increasing number of contracted electricity transfers.

- Operating procedures must be established to ensure that increased transmission access will not reduce the flexibility to accommodate emergency electricity transfers.

- Extensive monitoring, communications, and control systems must be in place to enable system operators to determine whether or not simultaneous system transfer limits have been exceeded. In the event that the limits are exceeded, clear and concise procedures will be required to effect the timely and orderly curtailment of electricity transfers as necessary to bring the systems within safe operating levels.

- Incentives are needed to ensure that future transmission additions will be constructed to provide sufficient capability to accommodate the anticipated increased levels of usage stimulated by increased competition and deregulation.

Future legislation in the transmission access and deregulation areas must recognize the need to maintain adequate system reliability. Resolution of the above issues in a careful and prudent manner is necessary if utilities are to maintain the level of reliability in the future that their customers have come to enjoy and expect.

Reliability Issues

Environmental Considerations

While environmental considerations are important, environmental regulations that reduce capacity, delay new facilities, or reduce the availability of existing facilities pose serious threats to electric system reliability. If an adequate and reliable electric supply is to be maintained, not only will new facilities be required, but the continued high availability of existing generation and transmission capacity will be essential.

Environmental Issues

Environmental regulations and their interpretations often delay the construction of new facilities or preclude the use of already constructed facilities. This directly impacts electric system reliability since new facilities may not be placed in service in time to meet future customer needs.

Environmental regulations should be carefully developed with realistic evaluations of their potential cost and effects. Stringent requirements may have adverse system reliability effects with no actual environmental or health benefits.

Nuclear Capacity

Restricted operation or premature shutdown of existing nuclear capacity, or the inability to complete construction and operate new nuclear capacity would seriously affect the reliability of electric supply. Regulations in the United States regarding spent fuel storage and low level radioactive waste disposal could potentially impact continued operation of 84,900 MW of nuclear capacity (13% of total 1987 U.S. capacity) and 18,200 MW of planned nuclear generation (25% of the total U.S. additions over 1988-1997). The existing 11,900 MW and planned 3,500 MW of nuclear capacity in Canada are less susceptible to changing regulations on spent fuel and low level waste disposal due to adequate on-site spent fuel storage capabilities and procedures for management of low level radioactive waste.

Fossil Capacity

In spite of the many actions already taken by U.S. utilities to control emissions, the issue of acid rain continues to be a major concern. New U.S. legislation could have an impact on the operation of at least the 174,000 MW of existing coal-fired generating capacity installed prior to 1975, the year in which the Clean Air Act became effective. Many units installed after 1975 could also be affected. By 1997, compliance with proposed federal legislation on emissions could cause as much as a 14,600 MW reduction in capacity (or about 5% of the total U.S. coal-fired generating capacity) due to premature retirements, power consumption of the additional emission control equipment, and decreased availability because of increased complexity. Regulations in Canada are not expected to have a significant impact on the capacity and availability of coal-fired generation because of some measures already taken.

Current and possible new regulations on water quality and thermal discharge also serve to limit both nuclear and fossil power plant capability during abnormally hot weather when the output of these plants is needed most.

Hydroelectric Capacity

Regulations requiring hydro reservoir control for environmental and recreational purposes can potentially impair operation of the 115,200 MW of existing U.S. and Canadian conventional hydroelectric generating capacity. In the United States, pressures to hold constant reservoir elevations during summer months and to maintain high dissolved oxygen levels downstream often conflict with electric system hydro requirements. The recent drought has highlighted the increasing competition over the use of hydro projects. Environmental constraints could also inhibit hydroelectric resource development in the United States. For example, although potential undeveloped small hydro resources in the Pacific Northwest are estimated to total about 4,000 MW, environmental constraints will probably limit actual development to less than 1,000 MW.

Transmission Systems

Adequacy of electrical supply depends on reliable operation of existing and planned transmission lines. Controversy regarding a possible correlation between electromagnetic fields and health effects is widespread, and in some cases has resulted in delay or cancellation of planned transmission facilities or removal of existing facilities. Health effect concerns have surfaced in Florida, New York, Ontario, Texas, Arizona, California, and Washington, and have impacted either existing or planned transmission facilities. Examples of such concerns include the rerouting of two existing Houston Lighting & Power Company 345 kV transmission circuits, the three year delay in the construction of a Florida Power Corporation 500 kV line, and the canceling by the city of Austin, Texas of 345 kV transmission improvements needed to meet reliability criteria. Any legislation or regulatory action to control electromagnetic field strengths near transmission lines should incorporate a careful evaluation of potential reliability effects.

Reliability Issues

Non-Utility Generation

Electric System Issues

Non-utility generators (NUGs), coordinated with the planning and operations of an electric utility, can be significant assets to utilities by supplying capacity that would otherwise have to be supplied by the construction of additional utility generators. NUG additions in NERC are projected to total 20,100 MW over the forecast period. They represent 22% of total planned capacity additions. The majority of these NUG additions, or about 19,800 MW, is planned for the United States.

Unit size and timing are critical in the installation of any new generation. For each utility there is an optimum mix of baseload and load-following generating units which best matches the customers' load characteristics while providing the lowest cost. Therefore, the integration of NUGs into electric utility systems must be closely coordinated with the utility.

Because electric systems were not originally designed for the integration of NUGs, they may not always be able to accommodate NUG additions without additional transmission. The siting of NUGs can be a reliability concern. Concentrations of NUGs in areas without sufficient transmission create load-generation imbalances or reduced stability margins. If NUGs are properly located at load centers, however, they may actually reduce the utility's transmission requirements.

Obligation to Serve

Most utilities serve their customers' electric demands under the guidelines of federal, state or provincial, and local regulating bodies. Non-utility generators are not required to fulfill this same commitment to serve, but rather are committed to the purchasing utility only by contractual obligations.

As with any private business enterprise, there is a risk that non-utility generators may be short-term entities because of the cost and availability of fuel, and changes in tax laws or environmental regulations resulting in changes in financial incentives and the future economic viability of the NUGs. Loss of significant NUG capacity can represent a reliability problem for the utility until that lost capacity is replaced.

Many NUGs, primarily cogenerators, are thermally integrated with industrial processes. Therefore, they are susceptible to the economic conditions associated with that process or industry. Since there is no statutory obligation to serve on the part of non-utility generators, the NUG economics and the NUG-utility contracts are the only assurances that NUG capacity will be available to help meet future electric demands. There is evidence that some NUG projects are not coming on-line as originally scheduled. Some NUG projects are two to three years late, while others may never materialize. These uncertainties add to the complexities of utility capacity resources planning.

Operation and Control

Since NUGs are normally designed and installed without load-following capability, the remaining utility generators must provide additional load-following which results in increased thermal and mechanical stress on the utilities' generating units. This, in turn, may reduce unit availability and adversely impact the reliability of the utilities' generators. In addition, NUGs must be dispatched on a coordinated utility system basis to avoid the shutdown or turndown of utility baseload units at off-peak hours (nights and weekends) especially in areas with an excess of NUG capacity. The utilities' large baseload units may not be able to be restarted for the next day's peak demand due to mechanical and thermal constraints thereby impacting electric system reliability.

Reactive power, often overlooked, is a critical technical issue. Instead of providing reactive power for voltage support, many NUGs consume reactive power or vars requiring the utility to furnish additional reactive support.

In those instances where NUGs supply reactive power, automatic voltage control may not be provided. Utilities with significant amounts of NUG capacity may have to provide supplemental static and dynamic reactive supply systems to maintain system reliability and to support system voltage.

Fuel Supply Adequacy

Utilities, when planning generation capacity, will generally commit for units which use fuels of various types and sources.

The availability and recent lower prices for natural gas, combined with short construction periods and relatively low capital costs, have made combustion turbines the predominant choice for many NUG facilities. A sudden change in the fuel supply environment or governmental regulations could drastically limit the ability of many NUGs to obtain fuel. Such a situation may reduce electric system reliability until this capacity can be replaced. Fuel diversity is becoming a reliability concern as gas-fired NUGs become a growing portion of electric utilities' planned capacity additions.

Reliability Considerations for NUG Integration

The NERC reference document, "Reliability Considerations for Integrating Non-Utility Generating Facilities with the Bulk Electric Systems," outlines measures to be taken by utilities and non-utilities in the integration of their resources. These measures involve technical issues which are similar to those required of utility generators and which should be addressed in the contractual arrangements between the utility and the NUG owner. Some of the key planning and operating considerations include:

- The interconnecting facilities of the NUG must be complete and fully coordinated with the utility facilities.
- NUG generation must be controllable and capable of being regulated and scheduled. Provisions should be made for backup electric supply to cover those instances of scheduled and unscheduled maintenance.
- NUG generation should be capable of being dispatched to match electric utility system load characteristics.
- The NUG should provide for complete communications, metering, and reporting facilities for coordinating with the utilities.
- Relaying and underfrequency tripping of NUG facilities must be coordinated with the host utility.
- The NUG should provide full and continuous voltage control, power factor control, and reactive power supply capability.
- A firm primary and backup fuel supply with storage should be available and committed for a large portion of the life of the NUG facilities.

Reactive Power

Non-utility generation has become an attractive strategy for many utilities seeking to avoid building new generating capacity. If the utility is able to negotiate terms and conditions for the purchase of NUG capacity and energy, then many of the aforementioned concerns may be minimized.

Regional Assessments

SUMMARY OF 1997 PROJECTIONS FOR THE REGIONAL RELIABILITY COUNCILS

Regions	Summer Peak Demand (Thousands of MW)	Annual Net Energy for Load (Millions of MWh)	Summer Generating Capability (Thousands of MW)	Transmission Systems[a] (Circuit Miles in Thousands)
ECAR	83.0	473	105	16.1
ERCOT	50.3	257	59	7.8
MAAC	44.5	244	55	7.1
MAIN	42.6	215	49	5.6
MAPP	31.4	173	40	20.9
NPCC[b]	96.2	648	131	35.3
SERC	137.4	721	163	29.2
SPP	57.4	273	68	12.2
WSCC	117.0	714	156	68.5
NERC-TOTAL[c]	**659.8**	**3718**	**826**	**202.7**
NERC-U.S.	**593.7**	**3210**	**725**	**156.4**
NERC-CANADA[b]	**64.8**	**502**	**99**	**45.8**

[a] Includes ac and dc transmission lines operating at 230 kV and above as of December 31, 1997.

[b] NPCC and NERC-Canada are winter peaking with 1997/98 winter peak demands of 112,200 MW and 88,400 MW, respectively. The 1997/98 winter generating capabilities are projected to be 132,500 MW for NPCC and 99,700 MW for NERC-Canada.

[c] Includes that part of the Comision Federal de Electricidad system in the northern portion of Baja California, Mexico, which is interconnected with the U.S. systems.

ECAR

EAST CENTRAL AREA RELIABILITY COORDINATION AGREEMENT

The electric capacity resources planned in the ECAR Region will satisfy the ECAR criteria for adequate reliability provided that availability of generating equipment continues at present levels, and load and capacity conditions are as projected. However, a small decline in the availability of generating equipment coupled with a slight increase in the rate of load growth, or other factors, such as implementation of manual or automatic control strategies, could quickly reduce the future electric system reliability to unacceptable levels.

The transmission network in ECAR is judged to be adequate to handle a wide range of contingencies. This judgment is based on analysis and reviews of transmission appraisals within ECAR and between ECAR and neighboring Regions. However, portions of the transmission network in eastern ECAR are expected to be heavily loaded much of the time for the foreseeable future. Operating procedures have been established to ensure that transfer schedules are limited to values that will make it possible to safely withstand any single generation or transmission contingency that might occur.

Actual			Forecast		
	Summer	1987	1988	1997	Growth Rate
	Winter	1987/88	1988/89	1997/98	(%/year)
Summer Peak–MW		72,561	71,770	83,031	1.6
Winter Peak–MW		68,118	69,972	81,123	1.7
Annual Energy–GWh		408,739	412,200	472,900	1.5
Installed Capability (Summer)– MW		95,319	97,380	104,527	0.8

Peak Demand and Energy

The aggregate of the peak demand projections by systems in ECAR shows that the Region is expected to be summer peaking throughout the 1988-1997 period. The average annual growth in projected peak demand for 1988-1997 is approximately 1.6% for summer and 1.7% for winter. Last year it was 1.8% for both summer and winter. A comparison of the projected peak demands for the common years 1988 through 1996, however, shows that the current summer peak demand projections are somewhat higher than last year and the current winter peak demand projections are somewhat lower.

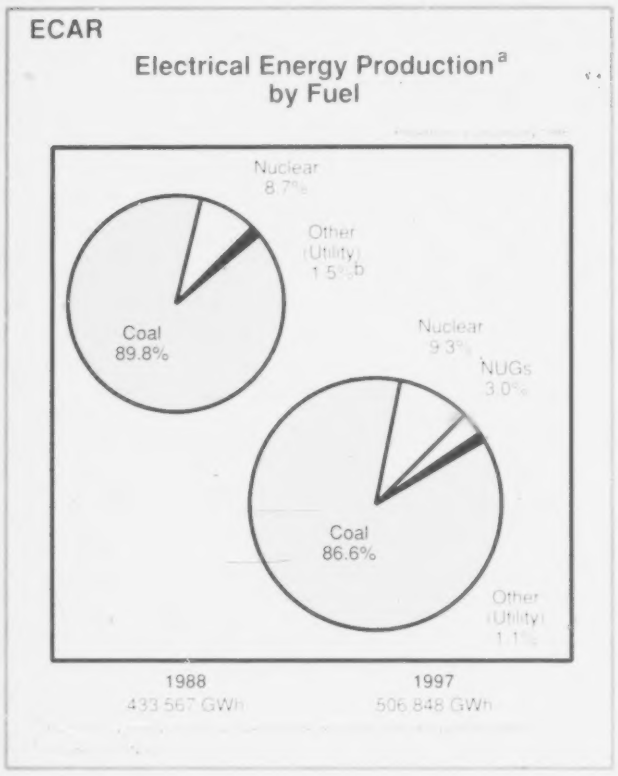
The projected annual net energy in ECAR shows an equivalent compound growth rate of about 1.5% per year over the forecast period. The projections are slightly higher this year than last for the early years of the forecast period and slightly lower for the later years. However, the difference for any one year is less than 1%. Coal-fired generating capacity will supply about 90% of the electrical energy produced in ECAR.

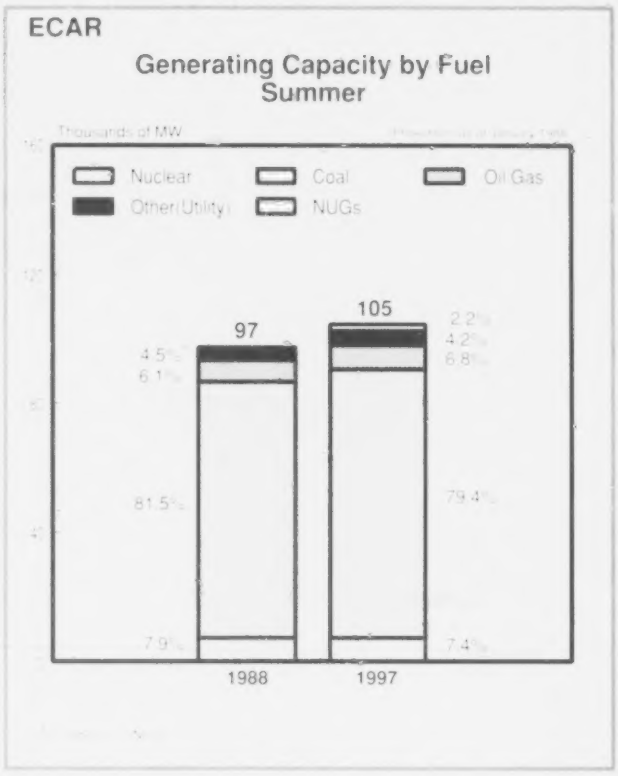
Nuclear is projected to increase its share of the total electrical energy produced from 8.7% in 1988 to 9.3% in 1997. The availability of materials and services for the nuclear fuel cycle (uranium conversion, enrichment, and fabrication) will continue to be adequate to meet requirements in ECAR. However, issues involving spent fuel storage and disposal must still be resolved.

Capacity Resources Adequacy

Two nuclear units, Perry 1 and Beaver Valley 2 – totaling 2,003 MW, were placed in service during November 1987 and a third nuclear unit, Fermi 2 – 1,093 MW, was placed in service during January 1988. The only other major unit additions scheduled during the forecast period are three coal-fired units: Rockport 2, Zimmer 1, and Trimble County 1 – totaling 3,095 MW. All three units are scheduled for service by the summer of 1991.

Non-utility generation is projected to increase from 168 MW at the beginning of 1988 to 1,329 MW by the 1991





summer season. However, there is uncertainty associated with any construction schedule and one or more of the NUG projects may be delayed because of circumstances such as construction difficulties or licensing problems.

Very little capacity is scheduled to be placed in operation after the summer of 1991. The generating unit additions projected after 1991 include 1,215 MW of combustion turbines and 979 MW of non-utility generation projects. The lead time required for capacity additions such as large fossil-fired units would make it virtually impossible to react to higher than projected load growth or an unexpected loss of capability (e.g., impact of potential acid rain legislation) in a timely manner.

Extensive appraisals of the adequacy of projected generating capacity margins have been carried out within ECAR using probabilistic techniques and procedures. The appraisals are based on consideration of the regional pattern of daily peak demands for each month of the study period, the status of scheduled generating unit additions, and the expected availability of generating equipment. The availability of generating equipment is the most critical parameter and high availability continues to be a goal of ECAR members. However, it may be increasingly difficult to maintain generating unit availability at the favorable high levels experienced in recent years since capacity margins will decrease as load grows, placing greater demands on generating units. In addition, by the end of the forecast period, the age of approximately 14% of the generating capacity in ECAR will be 40 years or more and approximately 28% will be 30 years or more. Environmental restrictions and any mandated additions of emission control equipment could further degrade the availability of generating equipment. The 1988 ECAR appraisal shows that if the load and capacity are as projected, the ECAR criterion for judging the adequacy of the projected resources will be satisfied throughout the 1988-1997 period provided that availability of generating equipment continues to exceed 72%.

Transmission System Adequacy

The electric utility systems in ECAR have developed an extensive and reliable high voltage and extra high voltage (EHV) transmission network that is interconnected with the networks in neighboring Regions at various voltage levels. The EHV portion of the network in ECAR consists of over 2,000 miles of 765 kV, over 800 miles of 500 kV, and over 11,700 miles of 345 kV transmission. Current plans call for the addition of approximately 100 miles of 500 kV and 200 miles of 345 kV transmission during the 1988-1997 period. These planned additions will enhance but not significantly alter the bulk transmission network that exists today.

In recent years, fuel cost differentials have created numerous opportunities for large scale economy transfers in addition to the long duration transfers scheduled well in advance. Significant amounts of energy transfers have been arranged on a daily and hourly basis. These intraregional and interregional transfers have become routine and will continue to be an important consideration in the operation of the interconnected transmission systems for the foreseeable future. These multi-party transfers have caused power flow patterns that were not anticipated at the time the transmission systems were originally planned, and they will continue to challenge the ability of operators to maintain a high level of reliability. This will be particularly true with the reduced operating margins that will be available.

Intraregional transmission system performance studies are conducted by ECAR to assure that the member systems meet regional reliability criteria. In addition, ECAR participates with neighboring Regions in system performance studies as part of the activities related to the MAAC-ECAR-NPCC, VACAR-ECAR-MAAC, and MAIN-ECAR-TVA interregional coordination agreements. These agreements provide for exchange of information among the parties related to bulk electric supply reliability and for review and analysis of such information.

Transmission performance studies are conducted prior to each summer and winter season and, on an annual basis, for some future period of interest. The purpose is to provide assurance that the planning and operation of the interconnected systems are properly coordinated. In general, these studies indicate that the ECAR bulk transmission systems should perform adequately under a wide range of credible system conditions. However, portions of the transmission systems in eastern ECAR have been heavily loaded much of the time because of energy transfers to the East. The single contingency reliability limit has been reached on many days and this is expected to continue.

Operating procedures have been established and actions are being taken to ensure that transfer schedules are limited to values that will make it possible for the systems to safely withstand any single contingency that might occur. Joint studies are now under way to investigate near-term operating procedures and to evaluate future system reinforcement alternatives that would provide an increase in total transfer capability.

Impact of Proposed Acid Rain Legislation

During recent years, a number of acid rain bills have been introduced in the U.S. Congress. Since coal is the predominant fuel used within the ECAR area — it is expected to supply almost 90% of the total electrical energy during the forecast period — the impact of compliance with acid rain legislation could be very severe on individual ECAR member systems and their customers.

In each of the past few years, scenarios were developed which provided results encompassing the probable range of the impact that such legislation could have on the reliability and adequacy of bulk electric supply in the ECAR Region. The scenario developed for the most recent assessment was based on the assumption that each system in ECAR would limit average annual emissions for fossil-fired units to 1.2 pounds per million Btu for sulfur dioxide (SO_2) and 0.6 pounds per million Btu for oxides of nitrogen (NO_x). A possible control strategy for achieving these emission limits was identified by each system. Results indicated a very adverse effect on the adequacy of ECAR generating capacity. In order to achieve the targeted average annual emission levels and still maintain a reliability level for 1997 equivalent to that provided by the current ten-year capacity plan, at least 11,000 MW of additional new generating capacity would be required. This new capacity would be needed (1) to offset the anticipated poorer availability of some of the generating units retrofitted with emission controls, and (2) to replace approximately 9,500 MW of capacity lost because of premature retirement, additional auxiliary electrical requirements, and other deratings associated with necessary plant modifications.

The East Central Area Reliability Coordination Agreement (ECAR) Region bulk power supply entity consists of 27 companies (18 electric utility systems and 9 joint or municipal systems) which serve either all or part of the states of Michigan, Indiana, Kentucky, Ohio, West Virginia, Virginia, Pennsylvania, Maryland and Tennessee.

ERCOT

ELECTRIC RELIABILITY COUNCIL OF TEXAS

Based on current capacity and load forecasts, capacity margins for the Region are adequate and will vary from 23.6% to 16.4% over the forecast period. Transmission system inadequacies continue to be a major concern in providing for future reliability and economy energy transfers. Peak demand and energy forecasts continue to indicate a reduced rate of growth, and projections for non-utility generation have leveled off.

Actual		Forecast		
Summer	1987	1988	1997	Growth Rate
Winter	1987/88	1988/89	1997/98	(%/year)
Summer Peak–MW	39,339	40,510	50,343	2.4
Winter Peak–MW	31,399	32,754	43,597	3.2
Annual Energy–GWh	195,400	198,771	257,489	2.9
Installed Capability (Summer)– MW	47,476	49,880	59,149	1.9

Peak Demand and Energy

The summer peak demand forecast by ERCOT member utilities indicates an average annual growth rate of 2.4% for the 1988-1997 period, a reduction from the 2.9% rate projected last year. The projected 1996 summer peak is down 1,321 MW from last year's forecast. Winter peak demand is forecast to grow at 3.2%. Utility-controlled load management programs, including interruptible loads, range from 1,108 MW, or 9.1% of the projected capacity margin in 1989 to 1,476 MW, or 13.8% of the projected capacity margin in 1994. Annual energy growth for the 1988-1997 period is currently estimated at 2.9%, compared to 3.3% for the 1987-1996 period. Slow economic growth continues to be the primary cause of the lower peak demand and energy growth rates.

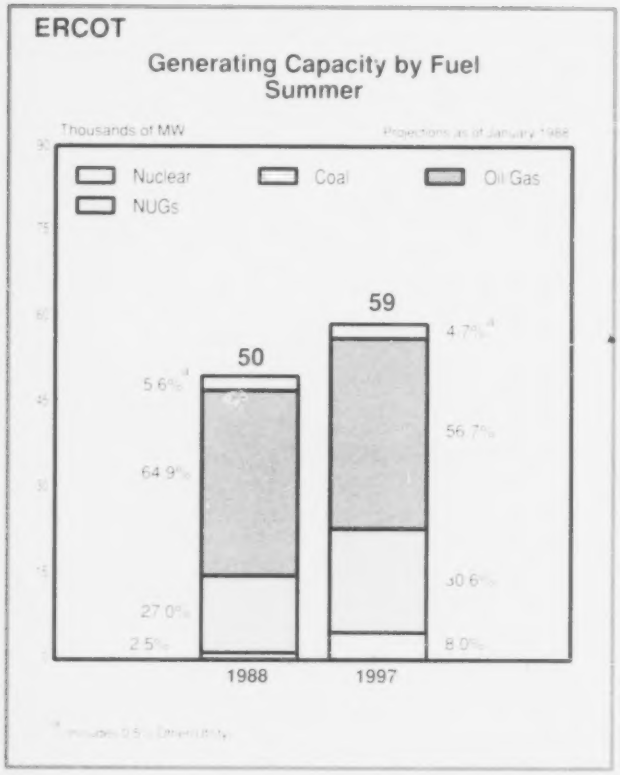
Capacity Resources Adequacy

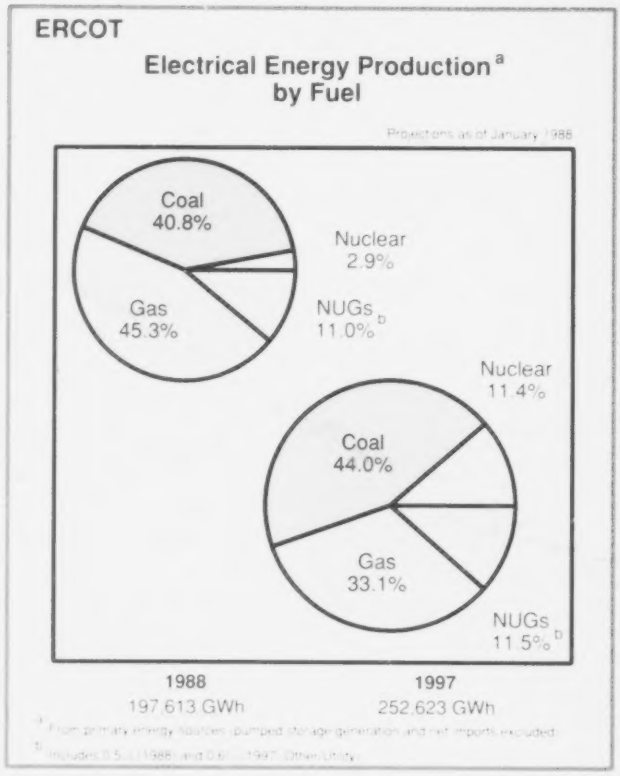
During 1987, utility-owned generating capacity declined by 201 MW. New utility-owned generating capacity scheduled for installation during 1988 through 1997 is 12,469 MW. This includes 5,218 MW of coal-fired capacity, 56 MW of utility-owned refuse burning capacity, 1,975 MW of combustion turbines, 420 MW of combined cycle generation, and 4,800 MW of nuclear generation. Net reratings of existing units are expected to add 618 MW, and units returned from deactivated status will add 169 MW. Retirements during the period are expected to remove 674 MW, and non-utility generating capacity is projected to decline by 31 MW. The total net increase in capacity is 12,551 MW, a 0.2% increase compared to last year's ten-year forecast. Non-utility generation, mainly cogeneration, is forecast to account for 2,537 MW or 5.1% of 1988 summer capacity resources and 2,506 MW or 4.2% of the 1997 summer capacity resources. Without the expected capacity contributions of non-utility generators, the Region's 1997 capacity margin would decrease from 17.8% to 14.2%.

The first of the Region's four nuclear units, South Texas One, became operational in March 1988. The second South Texas unit is scheduled to be completed in 1989, and the two Comanche Peak units are scheduled for service after the summer peak demand seasons of 1989 and 1991.

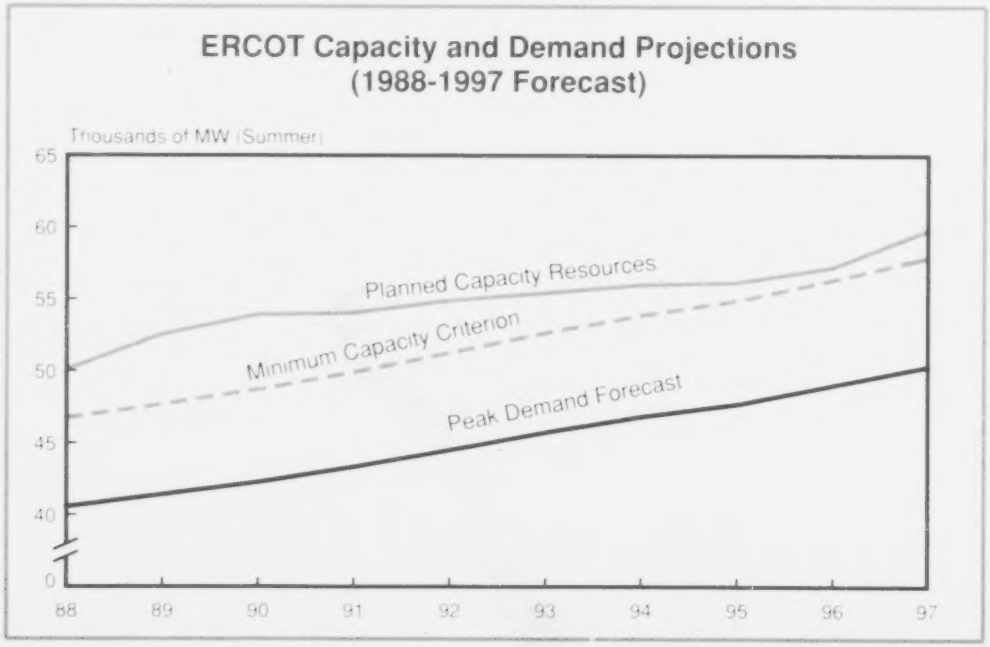
ERCOT is improving its fuel mix, but will remain heavily dependent on natural gas throughout the forecast period. Gas-fueled electrical energy production by utilities will amount to 45.3% of ERCOT's total annual energy requirements in 1988 and will drop to 33.1% in 1997. Electrical energy production by non-utility generators adds approximately 11% to these total percentages of gas-fueled energy resulting in a 44% projection for 1997.

The capacity margin within the Region is expected to range from a high of 23.6% in 1990 to a low of 16.4% in 1996. Capacity purchases, principally from non-utility generators, are being used to supplement ERCOT capac-





ity on both a short- and long-term basis. Projected capacity margins are greater than the planning guidelines adopted by the Region, thus planned capacity resources are expected to be adequate during the 1988-1997 period. Currently projected capacity resources could support an annual load growth of 2.7%, compared with 2.4% currently forecasted, without violating ERCOT planning criteria.



Transmission Adequacy

ERCOT members expect to install approximately 931 circuit miles of 345 kV transmission lines during the next ten years. This represents a 29% reduction from the ten-year projections made in 1987 and a 40% reduction from the ten-year projections made in 1986.

Expansion of the North DC Tie between ERCOT and the Southwest Power Pool from 200 MW to 300 MW is planned for 1990. The proposed South HVDC Tie has been replaced by a proposal to construct an alternate tie in East Texas. The East Tie will be jointly owned by utilities in ERCOT and the Southwest Power Pool and will have a capacity of 600 MW directly linking TU Electric with Southwestern Electric Power Company. Completion of the East Tie is scheduled for 1991.

The 345 kV double circuit line interconnecting Houston Lighting & Power Company (HL&P), TU Electric, and Texas Municipal Power Agency, which in November 1985 was deenergized as a result of a court decision, has now been rerouted and is back in service. Additional litigation which may affect the continued operation of this line was initiated in late 1987.

The proposed Salem-Zenith interconnection, a 345 kV double circuit line between HL&P and the Lower Colorado River Authority, is still awaiting Texas Public Utility Commission (PUC) action following a remand of the PUC's original disapproval by a Travis County District Court.

Of particular concern is a recent decision by the Austin City Council to cancel the construction of several 345 kV lines which were scheduled for service during 1988. Although an interim plan utilizing 138 kV lines has been approved, the Austin system is now exposed to blackouts caused by the outage of certain single transmission facilities and fails to meet ERCOT reliability criteria and NERC planning guidelines. Among the reasons voiced by the City Council members in making their decision was concern over possible health effects of electromagnetic fields (EMF).

Operations

Various forms of interutility and cogeneration wheeling have contributed greatly to the economic operation of the ERCOT system. During 1987, a total of 14,664 gigawatthours of interutility energy transfers occurred, with 8,962 gigawatthours of this total representing energy generated by non-utility generators. Use of the ERCOT Bulletin Board and Broker Systems continue to benefit ERCOT customers through the use of available transmission capacity to reduce production costs. PUC rules and ERCOT guidelines, which facilitate utility and qualifying facility access to the ERCOT transmission network along with wheeling compensation for all affected systems, have further stimulated the use of the ERCOT transmission network.

Reliability Issues

The key reliability issues of concern to the ERCOT member systems are as follows:

Construction of Additional Transmission Facilities – The increased use of the ERCOT transmission systems for both firm and economy energy interchanges has placed a significant strain on certain portions of the existing network. Of particular concern is the fact that the transmission systems in place today are not the systems that were planned, due to impediments delaying the construction of a number of planned facilities.

The 345 kV Salem-Zenith interconnection between HL&P and the Lower Colorado River Authority, which was rejected by the Texas PUC in November 1985, and the cancellation of all 345 kV construction by the Austin City Council in late 1987 are situations which have served to weaken the ERCOT transmission network. Further increases in the use of the transmission network for either reliability or economic reasons requires cooperation of utilities and regulators in overcoming impediments to the construction of critically needed interconnection facilities.

Natural Gas Supply – ERCOT utilities depend heavily on natural gas. Approximately 44% of ERCOT's electrical energy production in 1997 will be fueled by natural gas. The long-term availability of natural gas is therefore a major concern. While ERCOT utilities are currently benefiting from abundant supplies and attractive prices for natural gas, the relatively low gas prices have resulted in reduced drilling activities and deterioration of gas reserves. Despite having vigorously pursued fuel diversification, ERCOT utilities will, through the integration of non-utility generation into their resources, continue to be heavily dependent on natural gas. Non-utility generators, whose principal fuel is natural gas, serve to displace construction of utility-owned capacity which would use other fuels. While experts disagree on when it will occur, most agree that sometime in the future the current abundant supply of natural gas will be diminished and shortages will occur until exploration is increased and additional gas reserves are discovered.

Alleged Health Effects of Electromagnetic Fields – There is growing concern among ERCOT utilities that the public perception of EMF health effects may have a significant impact on the construction and continued operation of

transmission facilities within ERCOT. Recent actions regarding the construction of 345 kV circuits by the City of Austin Electric Utility and a condemnation case involving HL&P and the Klein Independent School District have brought this issue into sharp focus. The Texas PUC has recently initiated the appointment of a special committee to advise them regarding EMF research. There is considerable uncertainty at this time as to the full impact of this issue which will be watched closely by ERCOT member utilities.

MAAC

MID-ATLANTIC AREA COUNCIL

Actual			Forecast		
	Summer	1987	1988	1997	Growth Rate
	Winter	1987/88	1988/89	1997/98	(%/year)
Summer Peak–MW		40,526	39,581	44,491	1.3
Winter Peak–MW		35,775	34,785	41,607	2.0
Annual Energy–GWh		207,007	207,834	244,277	1.8
Installed Capability (Summer)–MW		48,553	48,582	55,313	1.5

Peak Demand and Energy

The trend of sustained load growth in MAAC continued in 1987 with an all-time record peak demand for the fifth consecutive year. The 1987 system peak of 40,526 MW was 8.0% higher than the 1986 summer peak and 6.6% higher than the 1987 forecast. The 1987 annual net energy for load was 5.1% higher than 1986.

Unusual weather conditions can cause significant variation in peak demand. The peak demand in MAAC for 1987 was 976 MW higher than would be expected for normal weather conditions. Even after correcting actual peak demand to normal weather conditions, MAAC experienced a growth from 1986 to 1987 of about 5.5%.

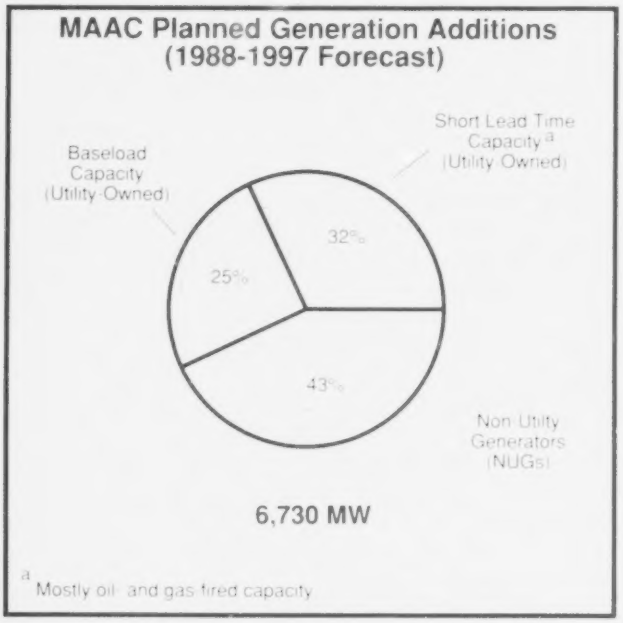
Adjustments to the MAAC forecast have been made to reflect recent peak demand experience. The current forecast for 1988 summer, based on normal weather conditions, is 1,037 MW higher than the forecast made last year for 1988. Similarly, the peak demand for 1997 summer is 1,640 MW greater than last year's projection. The ten-year peak demand annual growth rate is projected to be 1.3% compared to 1.2% in last year's forecast.

MAAC's summer peak demand projections include the effects of demand management programs. By 1977, the effect of the load management portion of these programs is projected to reduce peak demand by 2,470 MW.

Capacity Resources Adequacy

The installed generating capacity of MAAC is expected to increase by about 6,730 MW between 1988 and 1997. Non-utility generation will account for 2,860 MW or

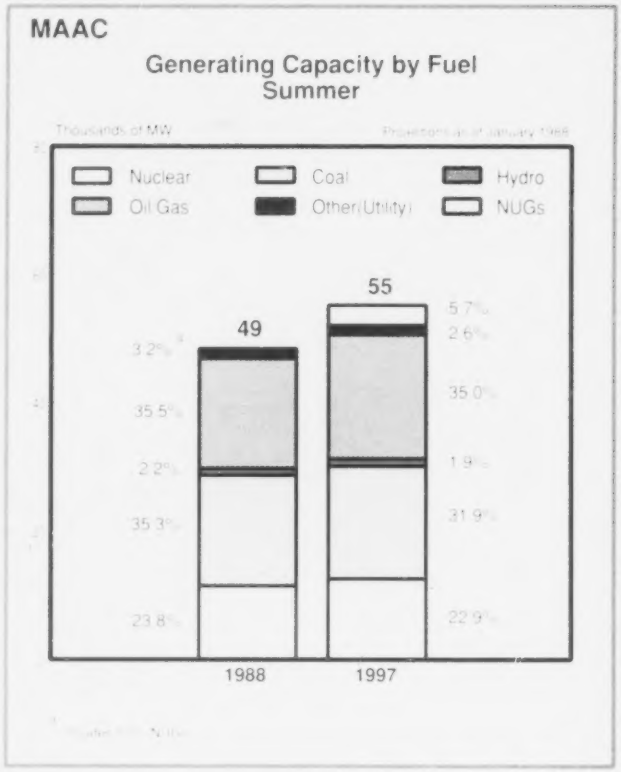
more than 40% of the increase in MAAC's capacity resources. Utility generating capacity will increase by 3,870 MW with the addition of the 1,055 MW Limerick 2 nuclear unit, the 640 MW Brandon Shores 2 coal-fired unit, and a net increase of 2,175 MW mostly from short lead time additions such as oil- and gas-fired combustion turbines. The following figure illustrates the type of capacity additions planned for MAAC during the assessment period.



Two factors that affect existing generating capacity availability can also be expected to impact the adequacy of capacity resources in the future. First, long-term outages of nuclear units can significantly impact the amount of capacity available during periods of peak demand. For example, in 1987 two Peach Bottom nuclear units (2,086 MW total) were unavailable during the peak season. These units will continue to be unavailable throughout the 1988 summer period. Second, the need to schedule maintenance or other planned outages of major generating units during the peak load summer period also reduces available capacity resources. About 1,800 MW of generation was unavailable due to such outages during the 1987 peak load days even though generator unit outage schedules were adjusted as much as possible to minimize summer outages. During 1988 summer, 1,300 MW of generation are expected to be unavailable due to planned outages.

Transmission Adequacy

The MAAC companies plan to add about 400 miles of 230 kV and 110 miles of 500 kV transmission lines by



1997. A portion of these additions is the completion of the Baltimore-Washington, D.C. 500 kV loop. This loop is critical for adquate interregional transmission transfer capability near MAAC's western interfaces and for adequate stability margins in the Baltimore-Washington, D.C. area.

Emergency assistance from neighboring pools on the 1987 summer peak days was less than expected, based on prior study results. It is expected to remain limited until transmission system reinforcements are made to interfaces in western MAAC and eastern ECAR. Needed reinforcements include completion of the Baltimore-Washington 500 kV loop, which has been delayed by judicial and regulatory procedures.

A major cause of the reduction in emergency assistance transmission capability planned and expected by MAAC is the simultaneous use of critical elements of the transmission network by MAAC members and other pools for various types of capacity and energy transactions. This is an increased use of the transmission system caused by recent changes in the way transmission systems are being used and by an expansion of the role of transmission in utility plans. It results in an adverse impact on MAAC's reliability unless transmission capability is restored. Joint studies are now under way to identify reinforcements that

would be necessary to improve transfer capability among the MAAC, ECAR, and VACAR areas.

Operations

The heavy loading of transmission systems caused by long distance capacity and energy transactions among utilities creates reliability concerns for system operators. Voltage limits become more prevalent. These conditions are more difficult to monitor and allow little time for the operator to take action once a severe operating condition develops. More information about neighboring systems is required for adequate monitoring. When generation or transmission outages occur, quick action and full cooperation by many control centers are required to return transmission loadings to safe levels. The MAAC, ECAR, and VACAR areas are working closely to strengthen monitoring capability, communications, and operator coordination to minimize the potentially adverse reliability impact that may result from a heavily loaded transmission system.

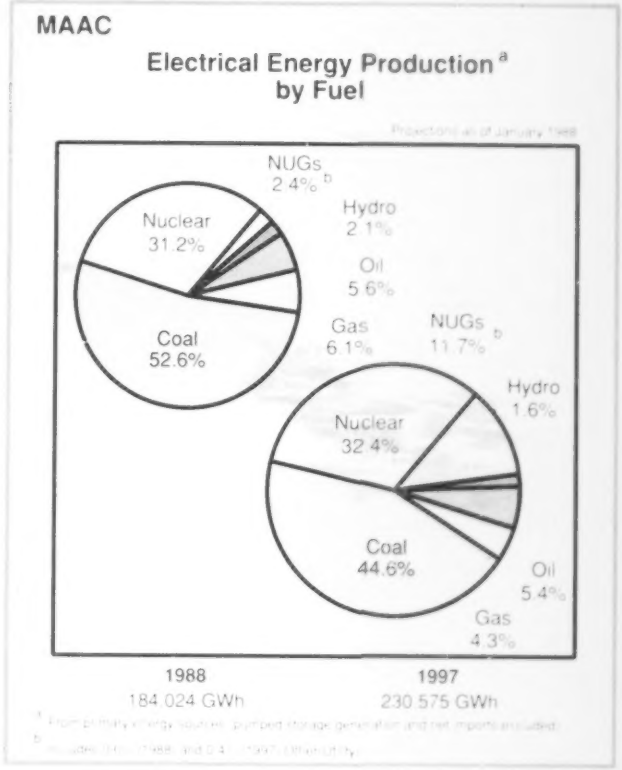
Reliability Issues

There are several factors that can adversely affect the adequacy of future supply capability in MAAC. The most critical is higher than projected load growth. Others are inadequate performance of load management programs, delay in utility and non-utility generator additions, limited transmission import capability, and decreased availability of existing generators. If any one of these factors falls short of expectations, MAAC could have a deficiency in electric supply capability in the next ten years.

Load Growth Higher Than Forecast – Peak demand higher than forecast can adversely impact adequacy of future supply capability. Based on recent experience, this is a real concern. In just five years, the MAAC projected demand for 1997 has increased by 2,275 MW. This is a significant change when considering the 10- to 12-year lead times required to build major new generation to cover the increased load projection. It illustrates the vulnerability of future electric supply to load growth exceeding forecast.

Load Management Effectiveness – The forecast assumes that by 1997 peak demand can be reduced by 2,470 MW with direct control load management and interruptible load programs. If these programs are not as effective as expected, other sources of additional supply capability would be required.

Planned Capacity Resource Uncertainty – Although planned generating capability is adequate to meet projected peak demand, some factors add uncertainty to these capacity plans. For example, more than 40% (2,860 MW) of MAAC's planned generating unit additions during the next ten years is from non-utility generators. Because this type of generation is just beginning to emerge in MAAC, there are many unknowns about construction schedules, unit dependability, and fuel supply.



The thrust of regulation at the federal level which focuses on increasing the competitiveness and efficiency in the wholesale market, and the thrust of regulation and policy in certain states in the MAAC Region, which encourages non-utility generators as the preferred suppliers, will likely change the characteristics of the electric utility systems. While utilities are responsible for providing electric service to their customers, the utilities will be unable to control the identity, timeliness, and other important aspects of their major suppliers, thus bringing into question the adequacy and timeliness of capacity resources. Only two major generating units are under construction in MAAC. Since the capacity margins are at minimum acceptable levels, it is important that these units, Limerick 2 and Brandon Shores 2, be completed as scheduled.

Emergency Transmission Capability – The transmission systems in and around MAAC continue to be heavily loaded for various types of economy and emergency utility transactions. The large number of simultaneous transactions cause a compounding of flows on facilities that are critical to interregional transfers. The result is a reduced amount of assistance that MAAC can expect from

other utilities during emergency conditions. Joint studies are under way to identify ways to reinforce the transmission network.

In addition, major new transmission reinforcements must be installed as planned. The Baltimore-Washington 500 kV loop has been delayed for at least 12 years. This project delay affects the transfer capability among the MAAC, ECAR, and VACAR areas. Without it, the reliability of supply in this area, particularly the Washington, D.C. area, is reduced. The longer the delay, the greater the reliability impact.

Availability of Existing Generation – Nuclear units are vital to maintaining adequate electric supply capability in MAAC, however, they continue to be vulnerable to extended outages. Operators of nuclear units must maintain the highest levels of management, safety, and operational performance to ensure that units continue to operate as dependable resources if adequate electric supply is to be provided for the Region during the next ten years.

MAIN

MID-AMERICA INTERCONNECTED NETWORK

Adequate generating capacity is expected to be available for reliable supply to the 1988-1997 peak demand and energy projections in MAIN. The transmission network in MAIN is adequate for reliable operation for both internal transfers and those involving adjoining Regions. A major future concern is the unknown effect on generating capability of possible regulatory actions related to acid rain. Additional reliability concerns are: supply adequacy should peak demand exceed projections, possible adverse impact due to operating near minimal generation margins, and the impact on reliability due to the increasingly more competitive atmosphere.

Actual			Forecast		
	Summer	1987	1988	1997	Growth Rate
	Winter	1987/88	1988/89	1997/98	(%/year)
Summer Peak–MW		37,458	37,308	42,637	1.5
Winter Peak–MW		30,618	30,054	35,476	1.9
Annual Energy–GWh		181,972	184,512	215,181	1.7
Installed Capability (Summer)–MW		44,805	49,607	49,391	0.0

Peak Demand and Energy

The 1987 summer peak demand in MAIN was 37,458 MW, a new all-time high, and was 4.2% above that of 1986 and 2.9% above forecast. The 1986 demand was 10.8% above the 1985 peak. During June and July of 1987, extremely hot weather prevailed over most of the MAIN area. Summer peak demand over the 1988-1997 period is forecast to increase at an average annual rate of 1.5%, which is slightly below the 1.6% rate forecast last year. There is little change from last year's estimates for specific future years. For example, the present forecast for the 1996 summer peak is only 0.3% or 135 MW higher than that made last year for 1996.

Annual energy use in MAIN in 1987 increased by 2.7% over 1986, which was 1.5% above that forecast for 1987. The ten-year forecast for growth in annual energy is 1.7%.

In general, the planned use of non-utility generation and load management in MAIN is very small compared to other Regions. No non-utility generation is included as installed capacity in 1988, and only 12 MW is projected by 1997. Excluding contractually interruptible load, estimates of the effect of directly controlled load management are less than 0.2% of summer peak demand throughout the forecast period.

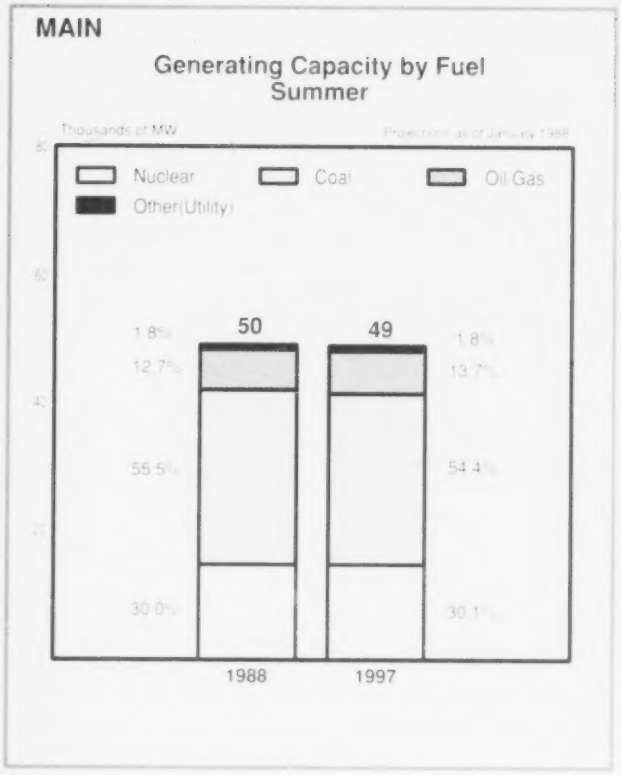
Capacity Resources Adequacy

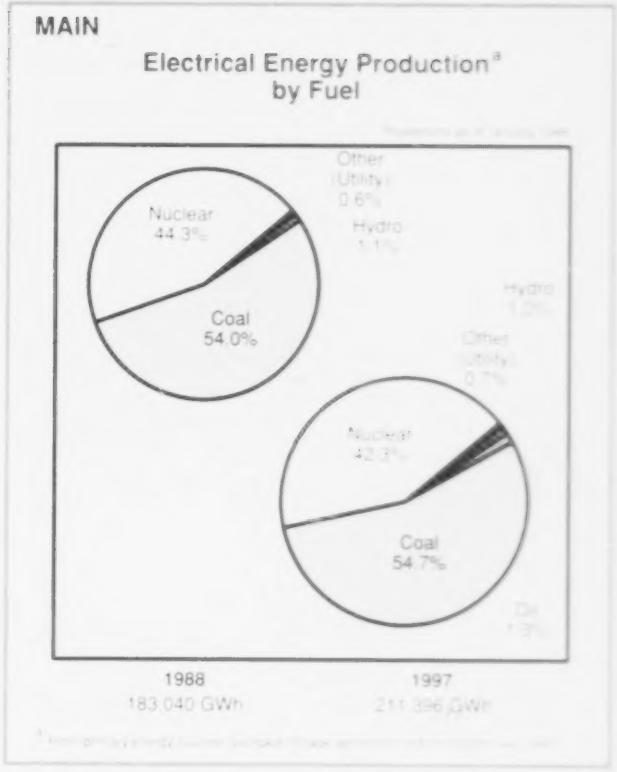
Generating capacity in MAIN is and will continue to be predominantly coal and nuclear as shown in the figures on the top of the following page.

Two nuclear units with a total capacity of 2,070 MW were placed in commercial operation in 1987 — Clinton 1 (950 MW) and Byron 2 (1,120 MW). Braidwood 1 (1,120 MW) has been placed in commercial operation, and Braidwood 2 (1,120 MW) is scheduled for service later in 1988. With these four units, generating capacity through 1997 should be adequate for reliable supply to the projected peak demands. No major additional units are planned for service during the 1989-1997 period.

Capacity margins are above minimum for several years with the new nuclear capacity in service. This situation will enhance reliability as well as facilitate scheduling of unit maintenance. The availability of low cost coal and nuclear generation will provide opportunities for economy transfers within MAIN and for possible sales to utilities in other Regions.

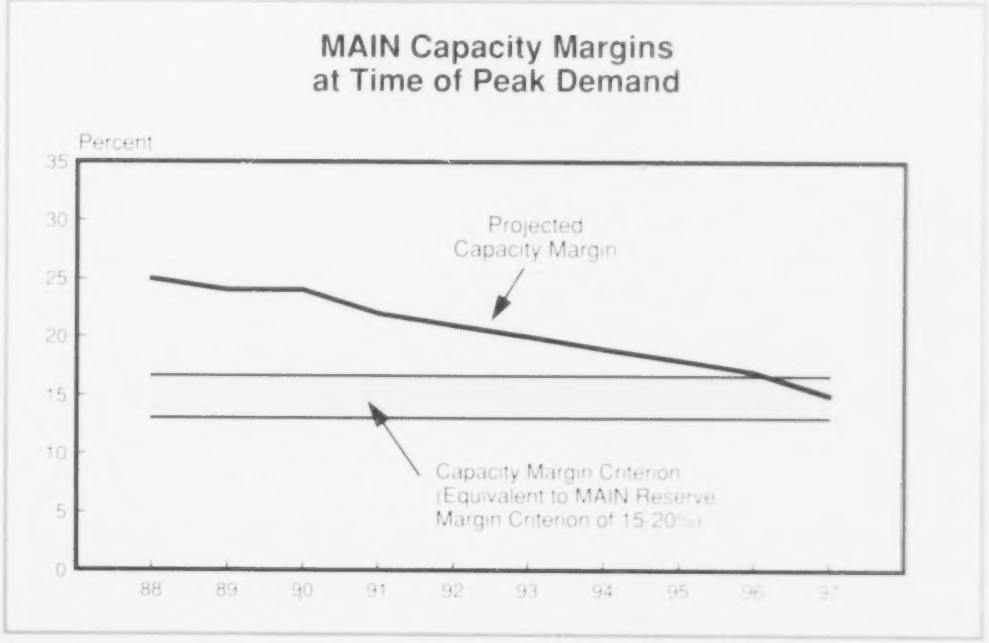
The generating reserve criterion in MAIN provides that utilities should maintain installed capacity at least 15 to 20% above the forecast peak demand in each year. This is equivalent to a capacity margin of 13 to 17%. The figure at the bottom of the next page shows expected capacity margins for the 1988-1997 period to be above the required minimum to supply projected demands. In 1997, planned capacity margin is 15.2%.





Transmission Adequacy

The transmission network in MAIN is adequate for reliable operation for both internal transfers and those involving adjoining Regions. Studies are conducted on a regular basis to assure that transmission capacity will continue to be adequate. These include near-term operating studies, longer-term planning studies of interchange capability, and extreme disturbance studies. Each of these studies



includes participation by representatives from other Regions to provide interregional coordination.

In 1987, transmission loading approached allowable limits (First Contingency Incremental Transfer Capability or FCITC) occasionally during transfers from MAPP to MAIN. Economy transfers have been limited when necessary in order to ensure secure operation.

Operations

Utilities are taking steps to assure reliable operation by providing additional system monitoring capability and by increasing system operator preparedness.

New computer facilities are being installed at the MAIN Coordination Center to improve the effectiveness of monitoring the bulk electric system through better exchange and analysis of reliability information such as loads, reserves, and the status of generation and transmission facilities.

Future Issues Influencing Adequacy

Some critical concerns in MAIN which have the potential to adversely impact electric system reliability include:

Acid Rain Legislation — Since coal is the major fuel used in MAIN for electricity production, new legislative or regulatory requirements for reduced sulfur dioxide (SO_2) and nitrogen oxides (NO_x) emissions may adversely affect reliability of supply due to the following:

- The maximum net output of most existing coal units would be reduced if retrofitted with emissions control facilities.
- The average availability of retrofitted units may also decrease.
- It may not be possible, nor economic, to retrofit some older units thus forcing premature retirement.

These factors would tend to reduce the capacity available from existing coal units with the result that new replacement capacity will be required. In addition, the installation of emission control equipment often requires lengthy unit outages resulting in less capacity to serve load during the periods of retrofitting. If new regulations are developed to control SO_2 and NO_x, the cost and lead time for the required replacement capacity must be given suitable consideration.

Peak Demand Growth above Forecast — MAIN's peak demand and annual energy forecasts are intended to have an equal probability of being high or low. The effects on reliability, however, are far from equal for actual peak demands higher or lower than forecast. If actual peak demands turn out to be greater than forecast, utilities will encounter difficulty in adding transmission and generation capacity in time because of the present problems in siting, licensing, and financing. Concern over the timely cost recovery of new generating capacity may delay initiation of needed projects. Thus, the risk to reliability is accentuated. On the other hand, if peak demands are lower than forecast, there may be some adverse economic impact, but reliability would not be jeopardized.

To illustrate this concern, if annual growth in peak demand turned out to be 1.8% compared to the projected 1.5%, the capacity margin would be at the minimum of 13% in 1997. If demand growth were 2%, capacity margin in 1997 would be 11.5%.

Operation with Lower Margins — As capacity margins decrease toward minimal levels over the next ten years, as shown in the capacity margin figure, reliability will decrease. For this reason, there is concern about operating the system at lower capacity margins than have prevailed in the past.

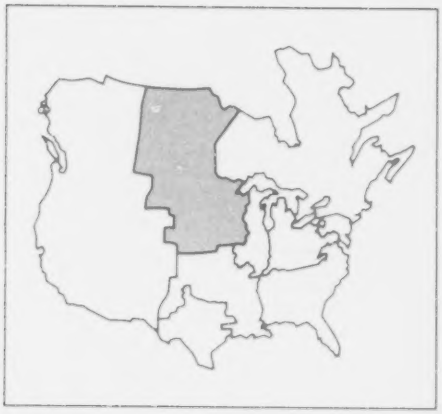
As utilities operate closer to minimal capacity margins, increased purchases and sales of capacity rather than economy energy will result. These capacity transactions will be more critical to reliability of service than the economy energy transactions now prevalent. Therefore, curtailing capacity transactions due to transmission system emergencies can impact customers much more significantly than curtailing economy energy transactions as has been done in the past.

With less reserve capacity available, flexibility in dealing with emergencies is reduced. Multiple contingencies, which the electrical system survived in the past due to greater than planned margins, will now result in more serious consequences. Continued improvement in system operations will be required to cope with the lower margins and heavier loading of the transmission systems.

Increased Competition — Reliability of the interconnected electric system requires the coordination of all connected utilities. Good coordination depends on sharing information in a timely fashion. Competition, on the other hand, works in the opposite direction. For example, knowledge of unit outages and their anticipated duration might affect pricing of available energy or capacity. Therefore, pressures may develop to withhold or delay sharing such information, which will have a negative impact on electric supply reliability.

MAPP

MID-CONTINENT AREA POWER POOL



Actual		Forecast		
Summer	1987	1988	1997	Growth Rate
Winter	1987/88	1988/89	1997/98	(%/year)
MAPP–U.S.				
Summer Peak–MW	23,162	22,840	26,192	1.5
Winter Peak–MW	19,335	19,703	22,756	1.6
Annual Energy–GWh	113,063	116,925	136,328	1.7
Installed Capability (Summer)– MW	28,586	30,619	31,345	0.3
MAPP–Canada				
Summer Peak–MW	4,048	4,172	5,217	2.5
Winter Peak–MW	5,371	5,538	7,005	2.6
Annual Energy–GWh	27,532	29,443	36,348	2.4
Installed Capability (Winter)– MW	6,629	6,551	8,617	3.1
MAPP–Total				
Summer Peak–MW	27,210	27,012	31,409	1.7
Winter Peak–MW	24,706	25,241	29,761	1.8
Annual Energy–GWh	140,595	146,368	172,676	1.9
Installed Capability (Summer)– MW	35,132	37,189	39,840	0.8

Peak Demand and Energy

The MAPP demand and energy forecasts are the sum of the individual MAPP member forecasts. The projected 1.5% and 1.7% average annual increase for MAPP-U.S. in summer peak demand and annual energy, respectively, are slightly reduced from the previous year's projections. The MAPP area continues to experience a depressed farm economy although the taconite industry has recovered slightly.

MAPP-Canada projects a 2.6% average annual increase in winter peak demand and 2.4% in annual energy. Both growth rates are reduced from last year's projections.

MAPP utilities continue to actively pursue various programs to reduce growth in peak demands. By 1997, utilities expect to be able to reduce peak demands by more than 1,000 MW through direct control of customer loads.

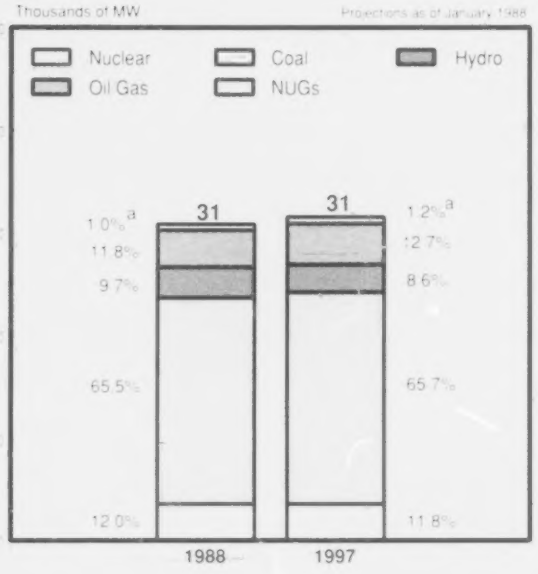
Capacity Resources Adequacy

An 800 MW coal-fired unit in Minnesota was placed in service in late 1987. There are no major generating units currently under construction in the U.S. portion of MAPP, although the coal-fired capacity is projected to increase by 540 MW during the 1988-1997 period. This increase consists of a 400 MW unit at the end of the reporting period, miscellaneous increases in existing plant capacity, and the return of mothballed units to service.

Manitoba and Saskatchewan are projecting the addition of 2,066 MW of generating capacity by 1997. This in-

MAPP-U.S.

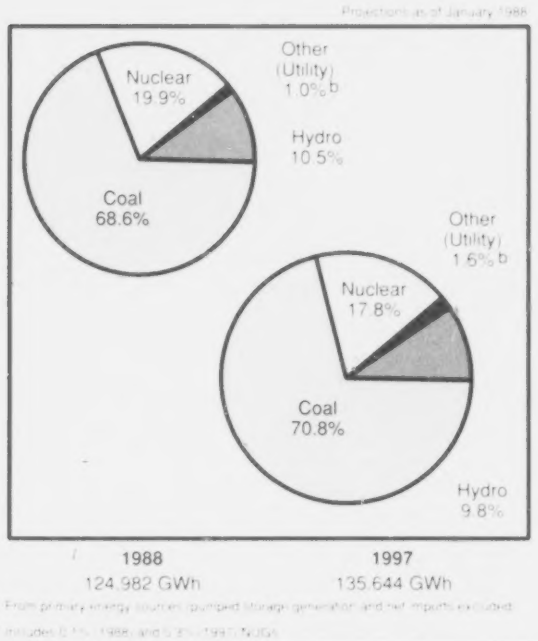
Generating Capacity by Fuel
Summer



a Includes 0.3% Other Utility

MAPP-U.S.

Electrical Energy Production [a] by Fuel



a From primary energy sources; pumped storage generation and net imports excluded.
b Includes 0.1% (1988) and 0.3% (1997) NUGs.

cludes the 1,200 MW Limestone hydroelectric plant in northern Manitoba and two 280 MW lignite units in Saskatchewan.

Through the purchase of existing capacity and the exchange of capacity on a seasonal basis, nearly 1,000 MW of new generating capacity have been deferred beyond the reporting period.

As the adjacent figures show, MAPP-U.S. and MAPP-Canada depend primarily on nuclear, coal, and hydro for electrical energy production. Less than 1% of the annual energy is expected to be produced by oil and gas during the assessment period. Non-utility generators form a minimal part in the resource plans for MAPP and by 1997 are forecast to represent less than 1% of the generation capacity. The capacity margin exceeds the criteria for reliable supply in all years. The minimum capacity margin of 21.4% occurs in the last year of the reporting period. The projected capacity resources are considered adequate to reliably supply projected peak demands and annual energy requirements.

Transmission Adequacy

The MAPP utilities have 18,939 miles of ac and dc transmission lines 230 kV through 500 kV in service. Over the next ten years, plans call for the construction of an additional 1,915 miles of transmission lines 230 kV and above. Transmission loading continues to be a concern for MAPP to MAIN transfers, but improvements on the underlying system currently under construction or planned will reduce the number of instances of limiting transfers.

Transmission facilities as planned are judged to be adequate throughout the ten-year review period.

Operations

Through the use of the MAPP computerized telecommunications network and economy transactions, the member utilities are able to achieve a major portion of the savings of a single system economic dispatch without the expense and complication of setting up a centralized dispatch center. This has allowed the maximum use of MAPP's existing resources and has minimized use of oil.

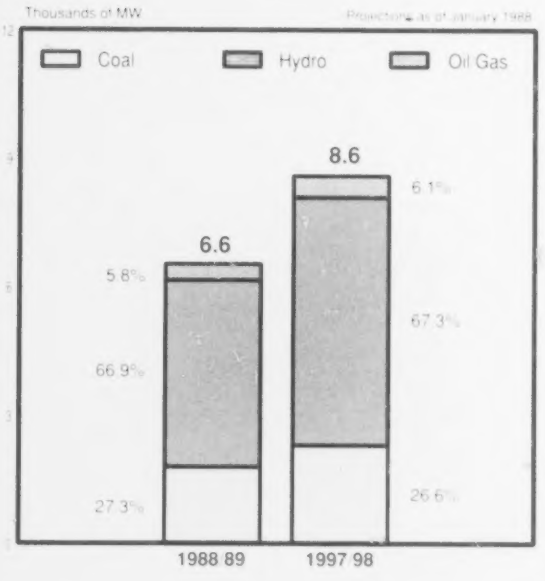
Reliability Issues

The major reliability issues in the MAPP Region are potential acid rain legislation, possible electromagnetic fields regulations, increasing use of the transmission system for firm capacity transactions, and uncertainty of direct control load management programs.

Acid Rain Legislation — Legislative efforts to further reduce emissions of sulfur dioxide, nitrogen oxides, and

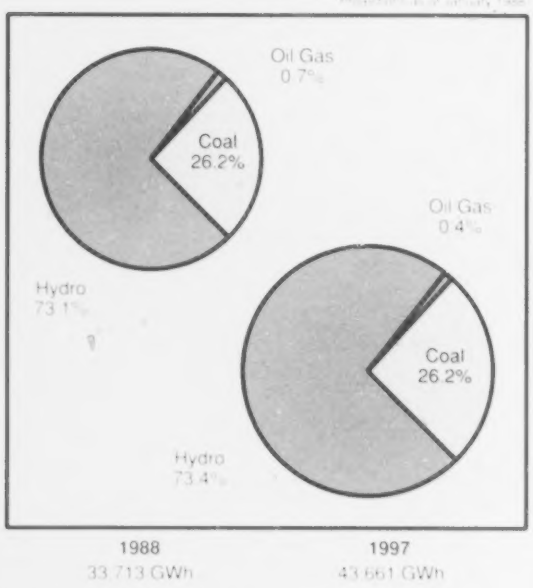
MAPP-Canada

Generating Capacity by Fuel
Winter



MAPP-Canada

Electrical Energy Production [a]
by Fuel



other substances from coal-fired power plants increase the uncertainty of the adequacy of the MAPP generating capacity. About 8,000 MW of MAPP's coal-fired generating capacity were installed prior to 1975. This capacity would be subject to:

- Extended outages to retrofit additional emission control systems
- Reduced capacity due to power consumption of the additional emission control equipment
- Reduced availability because of increased complexity.

Electromagnetic Fields Regulation — The current concern about possible adverse health effects of electromagnetic fields could lead to regulations that have a potential of affecting the operation of MAPP's existing and planned transmission network. This could significantly reduce future reliability of supply.

Transmission System Use — Increased utilization of the present capacity resources through purchases and seasonal diversity exchange agreements increases the committed loading on the transmission network thereby reducing the reliability margins. Further, greater dependency on the coordination and planning among the utilities becomes paramount to maintaining reliability standards.

Direct Control of Load Management — There continues to be great uncertainty with respect to MAPP's direct control load management programs. Customer acceptance has been favorable for those MAPP utilities that have pursued load management programs, but the actual frequency of customer interruptions has been only slight compared to the frequency that may be required in the future.

Customer acceptance over the long term and the amount of load available to be interrupted remain uncertain. The potential for unanticipated load exists and poses a threat of rapid capacity margin reduction should the customer with managed load find interruption of service unacceptable.

NPCC NORTHEAST POWER COORDINATING COUNCIL

Actual			Forecast		
	Summer	1987	1988	1997	Growth Rate
	Winter	1987/88	1988/89	1997/98	(%/year)
NPCC–U.S.					
Summer Peak–MW		42,651	43,038	50,866	1.9
Winter Peak–MW		41,902	41,788	48,139	1.6
Annual Energy–GWh		239,063	244,200	287,557	1.8
Installed Capability (Summer)– MW		52,531	53,714	59,702	1.2
NPCC–Canada					
Summer Peak–MW		35,935	36,136	45,350	2.6
Winter Peak–MW		52,139	51,737	64,053	2.4
Annual Energy–GWh		270,881	282,192	360,201	2.7
Installed Capability (Winter)– MW		59,128	59,404	70,984	2.0
NPCC–Total					
Summer Peak–MW		78,586	79,174	96,216	2.2
Winter Peak–MW		94,041	93,525	112,192	2.0
Annual Energy–GWh		509,944	526,392	647,758	2.3
Installed Capability (Winter)– MW		113,628	115,632	132,465	1.5

Peak Demand and Energy

All five NPCC Areas experienced peak demands and annual energy use in 1987 above the levels of 1986, and also above forecast values for 1987. Among the U.S. members of NPCC, summer peak demand in 1987 exceeded the 1986 level by 9.3%, and was 3.1% above forecast. Among Canadian members, 1987/88 winter peak demand exceeded the previous winter peak by 10.5%, or 5.1% above forecast.

Short-term peak demand comparisons do not necessarily give a true indication of long-term trends since year-to-year weather variations can have a significant influence. For comparison purposes, annual net energy for load usually provides a better basis of trends since it is less a function of temperature extremes. Electrical energy use by U.S. members of NPCC increased by 4.9% in 1987, 3.1% above forecast. In Canada, electrical energy use increased by 5.5%, 0.7% above forecast.

The 1988 ten-year forecasts of peak demand and annual energy have increased as compared to the 1987 forecasts in both the United States and Canada. The current forecast summer peak demand of U.S. members for 1996 (the last common year in both forecasts) is 2,670 MW higher than last year's forecast, an increase of about 6%. For

Canadian members, winter peak demand for 1996/97 is 670 MW higher than last year, an increase of about 1%. Annual energy forecasts for 1996 have increased by 5.6% for U.S. members and 2.0% for Canadian members. The 1988 ten-year forecast represents an average growth in peak demand for all of NPCC of about 2,000 MW each year.

Resources

Projected resources in New York, Ontario, Quebec, and the Maritime Provinces are adequate to meet forecast demand throughout the next ten years. However, this assessment assumes that capacity plans, non-utility generation projections, and the success of life extension and demand management programs can be realized. It also assumes that actual demand will not significantly exceed current forecasts.

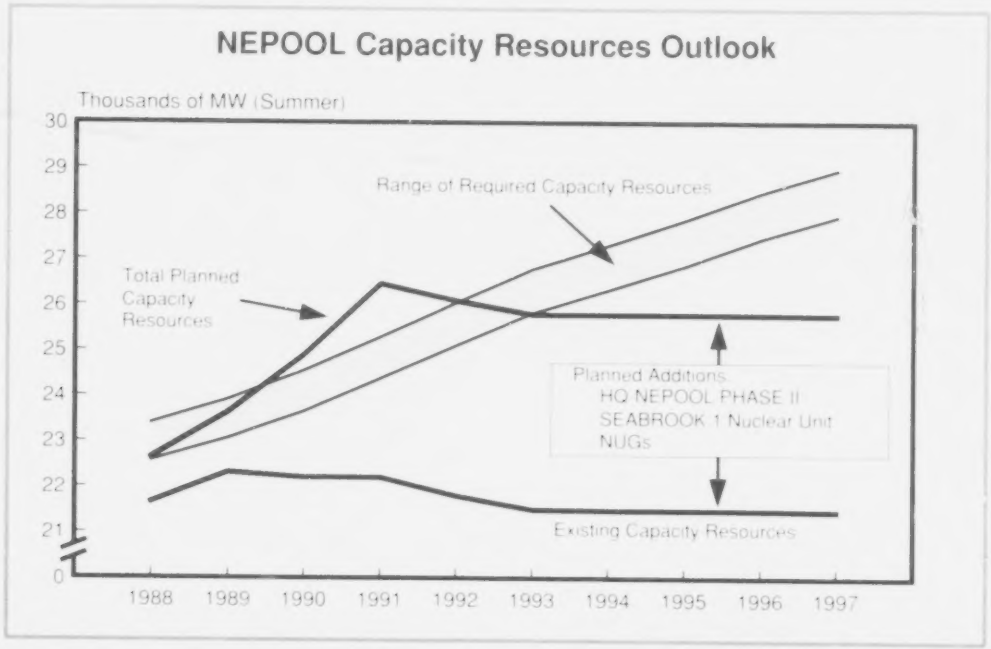
For the New England Power Pool (NEPOOL), supply and demand estimates indicate adequate capacity during the first five years (i.e., through the winter of 1992/93). The same qualifications mentioned above apply, as do the following: the Seabrook nuclear unit (1,150 MW) and the Phase II firm energy purchase from Hydro-Quebec (1,500 MW annual equivalent) are placed in service by winter 1989/90 and winter 1990/91, respectively.

Even with these qualifications, NEPOOL resources will fall below the requirements of NPCC's reliability criteria beginning in 1993 as shown in the adjacent figure. The resources will continue to decline throughout the rest of the assessment period, reaching a reserve margin of about 11% (10% capacity margin) in 1997 unless presently uncommitted resources are added. If the Seabrook unit is not permitted to operate, resource inadequacy will increase and occur at least one year earlier.

NPCC member systems are planning on a variety of options to maintain an adequate balance between supply and demand. These include new utility-owned generation, deferred capacity retirements from generating unit repowering and life extension programs, non-utility generating capacity, load reduction from demand management programs, and purchases from other utilities. The relative contributions of the various segments toward the net increase in resources is illustrated in the following table.

The New England figures for utility-owned capacity include the Seabrook nuclear unit. If this unit, which is the only major utility capacity addition over the next ten years, is not permitted to operate, the utility-owned capacity contribution will diminish.

Similarly, the New York utility-owned capacity includes the Shoreham nuclear unit (809 MW). An agreement recently negotiated between the Long Island Lighting Company (LILCO) and New York state, if approved, would transfer ownership of the Shoreham nuclear unit to the Long Island Power Authority, which is not permitted to operate the plant. Until the agreement is approved,



NET INCREASE IN NPCC RESOURCES (%)
(1988-1997 Forecast)

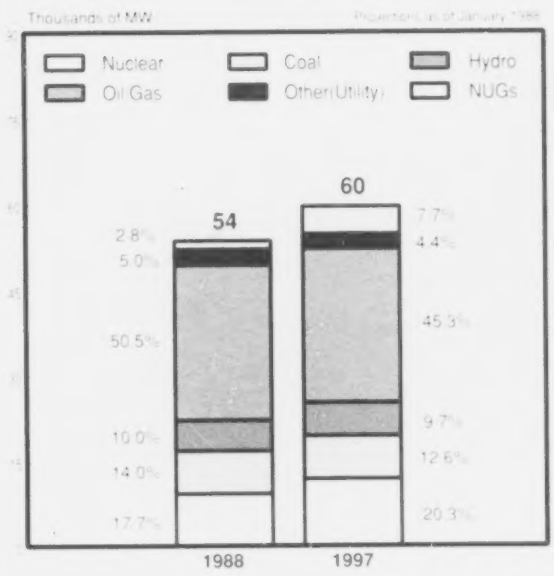
Resource Options	New York	New England	Ontario	Quebec	Maritimes (New Brunswick & Nova Scotia)
Utility-Owned Capacity	28	21	68	82	100
Non-Utility Generating Capacity (NUGs)	44	27	5	0	0
Demand Management & Interruptible Load	10	27	27	18	0
Purchases from Other Utilities	18	25	0	0	0
	100	100	100	100	100

LILCO is proceeding with a full power license before the Nuclear Regulatory Commission (NRC). The closing of Shoreham will result in continued marginal to inadequate system reliability for Long Island until additional generating capacity is added on Long Island and transmission capability from the mainland is installed in the early 1990s. The closing of Shoreham in a Region where capacity shortages may occur (in New England) in the early 1990s is of great concern.

Major reductions in the use of oil as a fuel for generating units have been realized in recent years. However, the U.S. portion of NPCC (New York and New England) remains the most heavily oil-dependent of NERC's nine Regions. Oil-fired generation will remain at about one-half of all utility-owned capacity in New York and New England over the next ten years, and will supply about one-quarter of annual energy requirements.

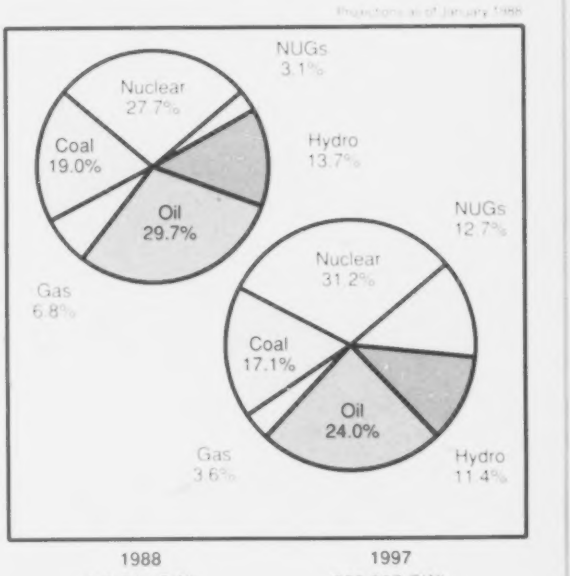
NPCC-U.S.

Generating Capacity by Fuel Summer



NPCC-U.S.

Electrical Energy Production [a] by Fuel



Transmission

The New England, New York, Ontario, and New Brunswick systems meet the NPCC transmission criteria, and will continue to do so throughout the assessment period. When Hydro-Quebec (HQ) and later Nova Scotia Power joined NPCC, it was with the understanding that they may not be able to satisfy all of the provisions of NPCC's transmission criteria insofar as their own systems were concerned. However, it was agreed that they would satisfy the requirements of the criteria insofar as neighboring systems are concerned. In other words, any contingency within the scope of NPCC criteria, even if it has a major adverse impact within Quebec or Nova Scotia, should not have an unduly adverse effect on the other systems. The April 18, 1988 blackout in Quebec, for example, did not result in outages in neighboring NPCC systems. An NPCC Working Group is presently assessing measures HQ has proposed which would bring the HQ system into full conformance with NPCC's transmission criteria.

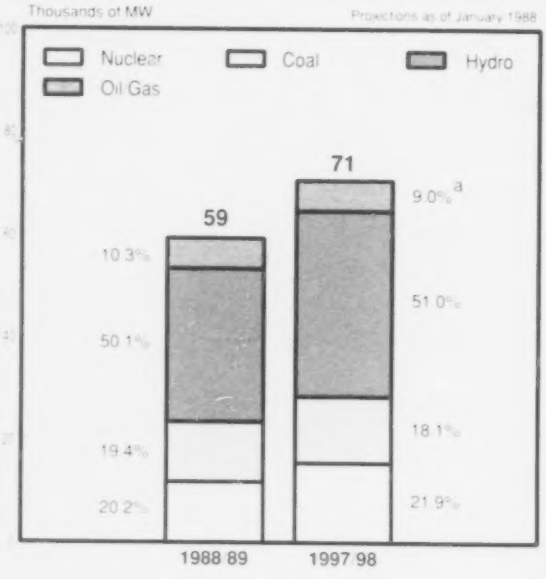
A number of transmission projects are under way to provide increased transfer capabilities among NPCC systems. The most widely known of these is the planned expansion of the present HVDC interconnection between HQ and NEPOOL. When completed in 1990, the HVDC interconnection will extend from the James Bay project in northern Quebec to Sandy Pond in eastern Massachusetts. Because of potential effects on other systems, this planned project has been the subject of extensive studies, both within NPCC and with neighboring Regions through the MAAC-ECAR-NPCC (MEN) organization. These studies have included investigations of allowable power flows on the HQ-NEPOOL tie as a function of west-to-east transfers in MAAC and New York, and vice versa, such that loss of the tie will not be more severe than individual single contingencies within MAAC or New York. To further enhance coordination, the results of the internal NPCC studies have also been made available to MAAC and ECAR.

The delayed Bruce 500 kV transmission in southwestern Ontario is now being constructed. However, until these lines are finally in service, there is some risk that they may not be completed on the currently scheduled dates and adversely impact system reliability.

Loadings on the bulk power transmission systems in NPCC have increased dramatically in recent years. This has been mainly due to transfers to take advantage of fuel price differentials, the location of generating resources farther from urban load centers, delays in completing new facilities because of the slowness of the public approval processes, and the growing reliance of systems in New England and New York on imports from Quebec.

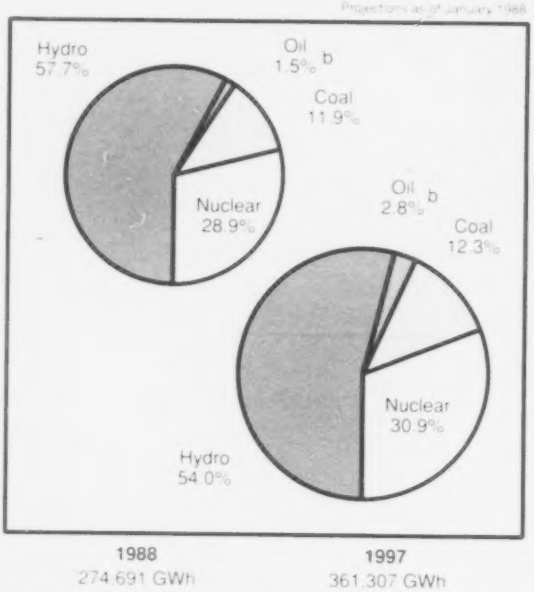
NPCC-Canada

Generating Capacity by Fuel
Winter



NPCC-Canada

Electrical Energy Production [a] by Fuel



[a] From primary energy sources; pumped storage generation and net imports excluded.
[b] Includes 0.1% in 1988 and 0.5% in 1997 NUGs.

The outlook is for such power flows to increase in the future. This will require the continued use of special protection systems and other sophisticated controls to observe appropriate NPCC transmission reliability criteria.

Coordination

Coordination, in both planning and operations, is the key to reliable system performance in NPCC. This includes coordination among NPCC's member systems and power pools, and coordination with neighboring systems. As electric systems become more complex and interdependent in the future, continued reliability will demand increased coordination and possibly different kinds of coordination.

NPCC has established a series of *Criteria*, *Guides*, and *Procedures* within the context of the NPCC Reliability Assessment Program. These documents define minimum planning and operating requirements, and the means to implement, interpret, and monitor conformance. Studies to this effect are carried out by the Council's eight permanent Task Forces, working groups established as required, and a full-time staff.

Interpool coordination agreements exist among the NPCC Areas and with neighboring systems. Further, NPCC is a party to Inter-Area Coordination Agreements with MAAC and ECAR, established in 1968. Through these and a similar agreement among MAAC, ECAR, and the VACAR Subregion of SERC, studies are regularly conducted among MAAC, ECAR, and NPCC (MEN) and VACAR, ECAR, and MAAC (VEM). All are performed under the auspices of a permanent Joint Interregional Review Committee made up of representatives from ECAR, MAAC, NPCC, and VACAR.

Coordination in Operations

Coordination in operations is achieved in NPCC through a hierarchical system. Criteria, guides, and procedures developed at the NPCC level are expanded and implemented at the Area level by the two U.S. power pools and four Canadian member systems. The U.S. pools and Canadian systems each operates a centralized control center for economic dispatch and overall system monitoring and control. In NEPOOL, control proceeds from the New England Power Exchange (NEPEX) dispatch center to satellite centers and then to the individual utilities. In the New York Power Pool (NYPP), control is directly from the NYPP dispatch center to the utilities. Voice and telecommunication systems link the New England Power Exchange (NEPEX), NYPP, and the Canadian control systems with each other and with neighboring systems.

NEPEX, NYPP, Ontario Hydro, and the Pennsylvania-New Jersey-Maryland Interconnection (PJM) maintain an Interpool Computer Network. Discussions are under way with Hydro-Quebec and the Maritime Area regarding their participation in the network.

The test procedure for Shared Activation of Reserves (SAR) continues to undergo actual tests with NEPEX, NYPP, Ontario Hydro, and PJM participating. It is anticipated that SAR will soon be formalized as an operating procedure.

A Working Group on Reactive Allocation has been working to identify those locations critical to voltage control within NPCC and on the interface with PJM. Another Working Group is investigating recent power oscillations observed on the NPCC system.

Through a "Procedure for Special Communications for Interconnected System Operation – Anticipated Emergency Conditions," weekly updates of interpool margins are provided and weekly conference calls are held among system operators. Given the dynamics of system operation, the conference calls are proving to be a valuable means of marshalling resources within NPCC and PJM during times of peak demand.

SERC

SOUTHEASTERN ELECTRIC RELIABILITY COUNCIL

Actual			Forecast		
	Summer	1987	1988	1997	Growth Rate
	Winter	1987/88	1988/89	1997/98	(%/year)
Summer Peak–MW		109,798	110,961	137,349	2.4
Winter Peak–MW		105,476	109,442	135,993	2.4
Annual Energy–GWh		573,735	580,983	720,827	2.4
Installed Capability (Summer)– MW		138,687	139,334	163,169	1.8

Peak Demand and Energy

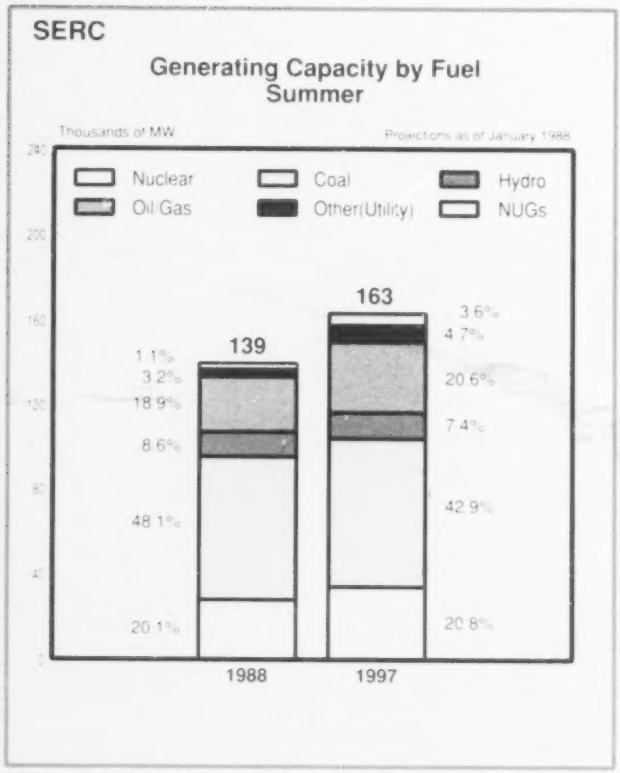
The SERC forecast has increased from that of last year, following energy growth (about 5% a year) that has occurred over the past two years. The SERC 1988-1997 forecast of average annual growth of summer peak demand is up from last year's 2.2% to 2.4%. The summer peak demand projected for 1996 (the common year of the past two forecasts) is also 5,000 MW higher than projected last year. Similarly, the winter peak demand growth rates have increased from 2.2% to 2.4%. Load management programs continue to be pursued by member systems and are expected to account for 3,165 MW of winter peak demand reduction by 1997. An additional 1,185 MW of contractually interruptible customer demand is projected to be available by 1997.

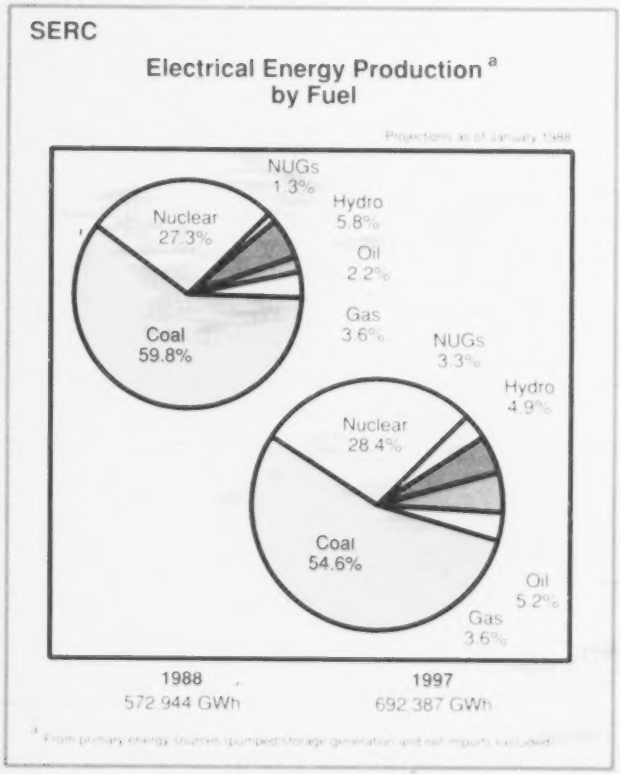
Capacity Resources Adequacy

Capacity additions within SERC for the 1988-1997 period include 4,354 MW in coal-fired units, 5,850 MW in nuclear units, 2,148 MW in pumped storage units, 4,464 MW in combustion turbine/combined cycled units, 220 MW in compressed air energy storage units, and 200 MW of conventional hydro capacity. This results in total capacity additions of 17,236 MW. In addition, approximately 6,200 MW of new non-utility generators are projected, an increase of 3,700 MW over last year's ten-year projection. Most of the large baseload units projected to come on-line during this assessment period are well under construction with near-term operating dates. During the later years of the forecast period, many systems are planning peaking or intermediate type capacity such as combustion turbines, combined cycle units, and capacity purchases from utility and non-utility generators because of system characteristics and regulatory and financial concerns.

NUGs will continue to become increasingly important sources of new capacity after 1990 for some systems of SERC. Because of the uncertainty of this least-cost generation expansion strategy, the potential exists for adverse impacts on the long-term reliability of electric supply. However, contractual provisions are being made to ensure the long-term and high availability of NUG capacity during peak demand periods and to ensure the proper integration of NUG capacity into the transmission system to prevent degradation of system reliability. With proper coordination, NUG capacity is capable of becoming an attractive and invaluable option to help meet the peak demands of the 1990s and beyond within SERC.

Projected generating capacity margins in SERC are judged to be adequate during the review period, based on current generating capacity expansion schedules and peak demand and energy projections. In addition to the installation of new capacity, modifications to existing units are under way and include unit upgrades, life extension programs, availability improvement programs, and reactivation of mothballed units. Electric supply adequacy would be adversely impacted by regulatory decisions or





other factors that would restrict the availability of existing or planned nuclear and coal-fired capacity.

Transmission Adequacy

The existing SERC transmission systems include almost 20,000 miles of 230 kV and over 7,000 miles of 500 kV transmission lines. During the review period, over 600 miles of 500 kV and approximately 1,700 miles of 230 kV lines are expected to be added in the Region, including two 500 kV transmission interconnections between SERC and SPP and one 500 kV transmission interconnection between SERC and ECAR. These projections represent a slight increase over projections made in 1987.

Permitting of a key 500 kV line in Florida continues to be delayed because of a state initiated review of electromagnetic field effects. The line, which was originally proposed for December 1987, is now scheduled for early to mid-1991. Until the line becomes operational, higher cost local generation will have to be operated to maintain system reliability. If the line continues to be delayed and with continued load growth, local generation will become insufficient to mitigate system reliability problems.

In December 1986, the final VACAR section of the Washington, D.C. 500 kV loop was completed. However, remaining sections of the loop will not be completed until 1994. This 500 kV loop is vital to the reliability of the bulk electric supply to the Washington, D.C. area and to the transfer capability among ECAR, MAAC, and SERC Regions.

SERC systems have coordinated transmission planning and operations to assure the continued use and expansion of a reliable transmission network. SERC is directly interconnected with the transmission systems in four other Regional Councils (SPP, MAIN, ECAR, and MAAC), and SERC members actively participate in inter- and intra-regional transmission studies. Analysis of these studies indicates that existing facilities, along with those planned to meet the future reliability needs of the SERC subregions, will provide adequate emergency transfer capability between SERC and other Regions and among the SERC subregions. All systems within SERC expect to meet SERC reliability criteria during the review period.

Operations

The SERC bulk electric transmission systems configuration ten years from now will not be significantly different from the present day system. The transmission systems are basically in place for most of the new capacity that is planned. Greater dependence on non-utility generation, an expectation of moderate load growth, and the sharing of generation capacity will reduce operating margins throughout this period. This will place an even greater

burden on the bulk transmission systems and will require continued coordination and communication among SERC systems and adjacent regional systems. Operators may be forced to take intervening actions on a more frequent basis to ensure that system security is maintained.

Studies are conducted on a frequent basis to ensure that transmission capacity will continue to be adequate. Detailed near-term operating studies and longer-range planning studies are made on a regular basis and involve each of the SERC subregions and representatives from other Regions to provide interregional coordination.

Reliability Issues

The key reliability issues of most concern to the SERC systems are as follows:

Transmission Access – The potential impacts of increased transmission access on electric system reliability continues to be a major concern to the SERC systems. Open access will likely result in heavier line loadings under normal conditions and thus reduce margin and transfer capability for potential emergency conditions.

Deregulation – Deregulation could allow some customers to shop around and purchase power from non-utility sources or other utilities and thus the fixed cost of a system's generation and transmission capacity would be borne by the remaining customers. Reliability could suffer because of the increased complexity in planning and operations due to a large number of potential transactions.

Heavy Transmission Loadings – Heavy loadings on portions of the SERC transmission systems are projected to continue throughout the assessment period as systems strive for optimum economic operation. Even though major reliability concerns are not anticipated, several key transmission interfaces or interconnection lines between utilities, subregions, and Regions will continue to be monitored because of their high loadings during certain interregional and intraregional energy transfers.

Acid Rain Legislation – A major environmental and regulatory issue among systems in SERC is potential acid rain legislation. Most proposed legislation would have a detrimental impact on the availability of existing fossil generating units (i.e., deratings and/or forced retirements). SERC utilities are actively involved in projects to identify the significance of acid rain legislation in their areas as well as the effect of emission equipment retrofit.

Electromagnetic Field Health Effects – There are increasing concerns among SERC systems that public perception of the EMF health effects issue may have a detrimental impact on the construction and continued operation of transmission facilities. Continued EMF research is supported by the SERC systems.

SERC membership includes 29 systems located in nine states in the southeastern United States. SERC is divided into four diverse subregions covering an area of 335,650 square miles which are identified as Florida, the Florida peninsula; Southern, the geographical area of the Southern electric systems; TVA/ML, Tennessee Valley Authority area and VACAR, the Virginia-Carolinas area. Total population in the Region is about 75 million.

SPP

SOUTHWEST POWER POOL

Actual			Forecast		
	Summer	1987	1988	1997	Growth Rate
	Winter	1987/88	1988/89	1997/98	(%/year)
Summer Peak–MW		47,723	48,330	57,380	1.9
Winter Peak–MW		34,472	36,127	43,862	2.2
Annual Energy–GWh		228,260	230,049	273,379	1.9
Installed Capability (Summer)– MW		66,342	65,621	68,159	0.4

Peak Demand and Energy

The agriculture and petroleum industries have been experiencing economic recessions. This is evidenced by over 200 bank closures in a significant portion of the Southwest Power Pool (SPP) since 1982.

The continuation of this economic condition is manifested in the ten-year forecast of subregional electric peak load growths. The Southeastern Subregion is forecasting a 1.4% annual peak demand growth for 1988 to 1997, while the West Central and Northeastern Subregions are predicting a 2.4% and a 2.3% annual peak demand growth, respectively. For the total Region, the 1988 to 1997 annual peak demand is forecast to grow at a 1.9% rate to 57,380 MW.

Last year, annual energy was forecast to increase at an average annual rate of 2.1% between 1987 and 1996. A comparison of the current ten-year forecast with that made last year shows that the 1996 annual energy is 1,340 GWh (0.5%) more than last year's forecast.

Capacity Resources Adequacy

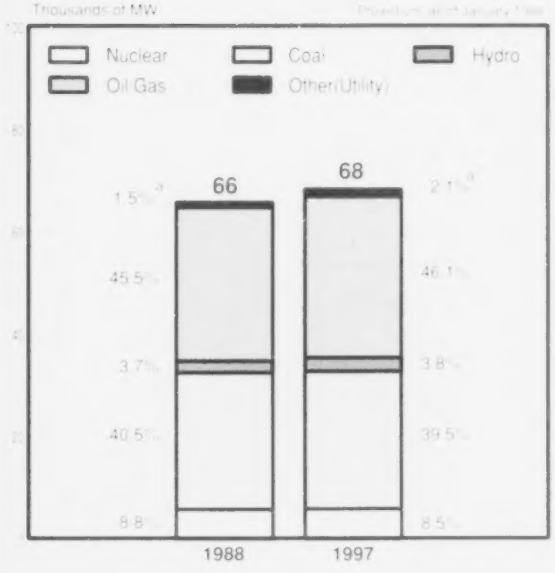
SPP anticipates adequate generating capacity margins through the ten-year period, however, turnaround of the agriculture and petroleum industries could cause a rescheduling of proposed generation additions.

In 1987, SPP had a total installed generating capacity of 66,342 MW, including 31 MW of non-utility generation. By 1992, 420 MW of projected retirements and reratings are offset by an anticipated 426 MW of additional non-utility generation. Of this anticipated non-utility generation, 400 MW is expected in the West Central Subregion. By 1997, the forecast is for a total installed generating capacity of 68,159 MW which includes 582 MW of non-utility generation. In the next decade, 2.7% of generating capacity will be added to the 1987 total installed capability and non-utility generation will compose 0.9% of this capacity. Installation of small generation, reratings and retirement of existing units, and reactivation of current mothballed units will result in a net loss of 92 MW of existing capacity. The addition of 1,189 MW of combustion turbines, 169 MW of combined cycle units, and 551 MW of non-utility generation account for the increase in total installed generating capacity by 1997.

Over the forecast period, the fuel mix remains fairly constant with coal providing 54%, gas 26%, and nuclear about 15% of the fuel requirements. At the present time, it is felt that there are adequate supplies of fossil fuels for this forecast period. However, as has been experienced, regulatory actions could result in shortages of oil and gas for electrical generation and therefore a serious capacity problem for the utilities of SPP with a significantly high ratio of gas generating capacity.

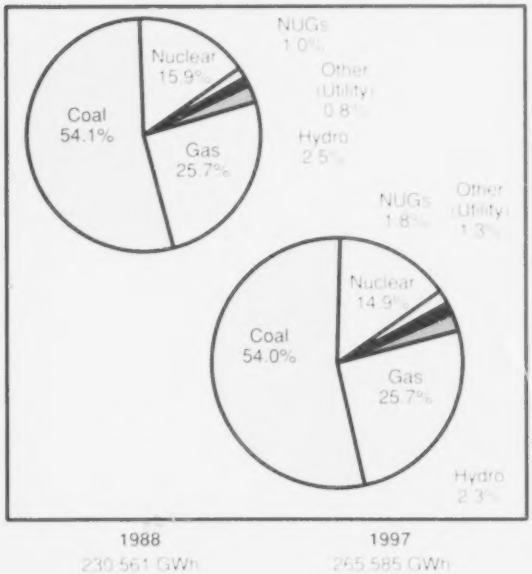
SPP

Generating Capacity by Fuel
Summer



SPP

Electrical Energy Production [a]
by Fuel



Transmission Adequacy

The SPP transmission network is judged to be adequate and there are no major bottlenecks to economy or emergency energy transfers for the forecast period.

During 1987, key transmission additions included the 500 kV line between Dell substation, near the City of Blytheville, Arkansas, and Shelby substation, just north of Memphis, Tennessee and the 500 to 230 kV transformer at Freeport, south of Memphis. Both of these additions are new interconnections between TVA and Middle South Utilities System.

In the next five years, it is projected that 599 miles of 230 kV, 250 miles of 345 kV, and 45 miles of 500 kV transmission will be installed. Between 1993 and 1997, an additional 213 miles of 230 kV, 139 miles of 345 kV, and 242 miles of 500 kV are planned.

Operations

With TVA returning their nuclear units to service, energy transactions which have caused some operating problems in the past will be greatly reduced. The back-to-back dc tie between ERCOT and SPP has become very important, as lower than expected gas prices in Texas allow the transfer of economy energy in addition to the output from jointly-owned generation into SPP. There are a number of troublesome, isolated areas which are closely monitored. When required, operating guidelines are implemented to reduce line loadings under contingencies.

For this forecast period, it appears that the transmission systems as planned will be adequate and there are no conditions requiring special protective systems to be installed in the Region.

Regional and Interregional Coordination

SPP continues to work with adjacent Regional Councils in studying economy and firm energy transfers.

SPP has started a program of gathering transmission line outage data for voltages 345 kV and above and will be developing transmission outage statistics for use in evaluating system performance and reliability.

Utilities in Kansas and Missouri are completing a two-year study which reviews capacity margins and long-range electric supply requirements. This study will recommend several possible expansion plans for the two-state area on a single operating concept basis.

SPP began conducting probabilistic generation reliability studies to determine indices for each subregion and for the Region as a whole. These indices will ultimately be

used to establish guidelines for capacity margin analysis and future electric supply reliability.

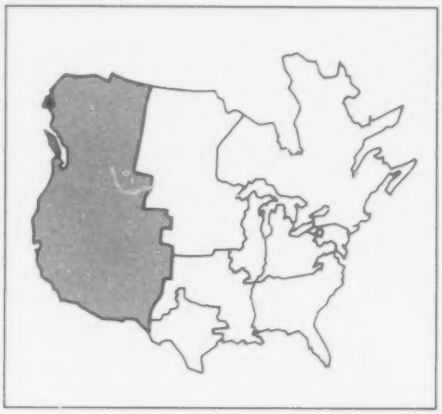
Reliability Concerns

At the present time, the primary reliability concern of the utilities in SPP involves the issue of transmission access and in particular the impact of "wheeling out." It must be stressed that "reliability and economic dispatch considerations must be determined by the utilities who own and operate the transmission network" and bear the obligation to serve. Reliability is greatly influenced by energy purchases and sales to others when delivered over the transmission network.

WSCC

WESTERN SYSTEMS COORDINATING COUNCIL

WSCC's projected supply of electricity and the transmission network are generally adequate to serve the forecast growth in customer requirements over the next ten years. However, there is growing concern that the restructuring of the industry through deregulation, increased competition, and mandated transmission access could result in a long-term decline in bulk electric system reliability within the Region.



Actual		Forecast		
Summer	1987	1988	1997	Growth Rate
Winter	1987/88	1988/89	1997/98	(%/year)
WSCC–U.S.				
Summer Peak–MW	82,967	85,932	101,394	1.9
Winter Peak–MW	81,182	81,889	95,140	1.7
Annual Energy–GWh	496,293	514,086	602,019	1.8
Installed Capability (Summer)– MW	125,819	123,022	134,049	1.0
WSCC–Canada				
Summer Peak–MW	10,208	10,917	14,235	3.0
Winter Peak–MW	12,354	13,327	17,385	3.0
Annual Energy–GWh	76,225	79,516	105,442	3.2
Installed Capability (Winter)– MW	17,856	17,675	20,138	1.5
WSCC–Mexico				
Summer Peak–MW	649	700	1,306	7.2
Winter Peak–MW	455	521	972	7.2
Annual Energy–GWh	3,172	3,415	6,335	7.1
Installed Capability (Summer)– MW	1,028	1,028	1,708	5.8
WSCC–Total				
Summer Peak–MW	93,811	97,264	116,559	2.0
Winter Peak–MW	93,991	95,492	113,497	1.9
Annual Energy–GWh	575,690	597,017	713,796	2.0
Installed Capability (Summer)– MW	144,741	141,882	155,622	1.0

Peak Demand and Energy

WSCC's 1988-1997 forecasts of peak demand and annual energy are somewhat reduced from last year's forecasts both in terms of average annual growth rates and projections for specific years. The Region's 1987 summer peak demand, winter peak demand, and annual net energy for load are also below their 1987 forecast values by 3.1%, 1.3%, and 0.8%, respectively. Both WSCC's summer peak demand and annual net energy for load are forecast to grow at 2.0% per year over the 1988-1997 forecast period. This reflects a reduction in the 1996 summer peak demand of 3,793 MW compared to last year's 1996 summer peak demand forecast. Similarly, WSCC's projected 1996 annual net energy for load is 4,811 GWh less than the 1996 energy load reflected in last year's forecast.

WSCC

Capacity Resources Adequacy

The net generation additions (16,771 MW) projected over the next ten years are considerably less than the net generation additions (37,400 MW) placed in service during the past ten years. This significant reduction, by a factor of more than 2.2, in planned resource additions is in response to the lower load growth projections of recent years and the surplus resources available throughout WSCC. Non-utility generation represents 31.4% (5,268 MW) of the planned ten-year generating capability additions. Although non-utility generation additions represent a significant percentage of the total resource additions, these additions will account for only 4.9% of the Region's total resources by 1997.

California leads the WSCC Region in projected non-utility generation additions. Non-utility generation is projected to increase from 1,992 MW to 6,615 MW over the next ten years in the California-Southern Nevada Power Area reflecting a 230% increase.

Due to the financial risks associated with the large capital expenditures required to build new generating facilities, utilities in WSCC are reluctant to commit to large new projects. As a result, "flexibility" is a key element in the planning process to minimize the commitment to large capital expenditures. Deferral of new resources will postpone the retirement of older generating plants including gas- and oil-fired units, thereby extending the utilization of gas and oil as primary fuels. Heavy inter-area transfers of hydro and coal-fired energy will continue as a means of reducing utility gas and oil requirements and lowering the cost of electricity to the customer.

The generating capacity margins of WSCC range from 33% to 26% over the assessment period and are judged to be adequate to reliably meet customer demands.

Transmission Adequacy and Operations

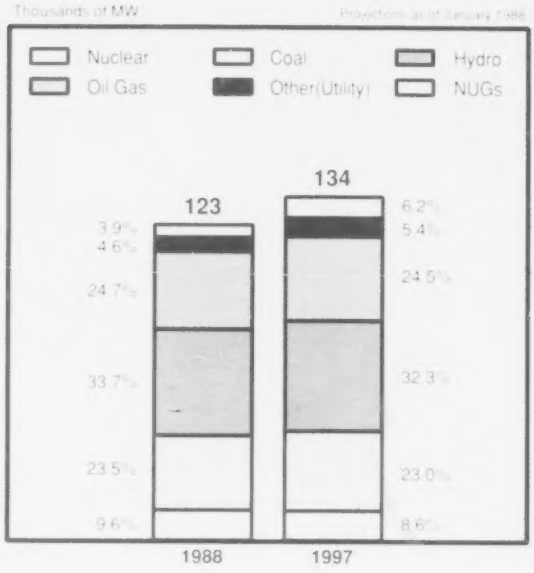
The WSCC transmission system is adequate to accommodate anticipated firm and most economy energy transfers during the ten-year period (1988-1997).

WSCC member systems are making a concerted effort to maintain an acceptable level of existing and future system reliability while accommodating higher transfer levels. During 1987, Pacific Gas and Electric Company's portion of the new ac Pacific Intertie centralized remedial action scheme was placed in service. Installation of the new scheme is part of an overall project to improve the reliability of the ac Pacific Intertie.

Operating restrictions (defined by nomograms) continue to be required to limit simultaneous imports of electricity

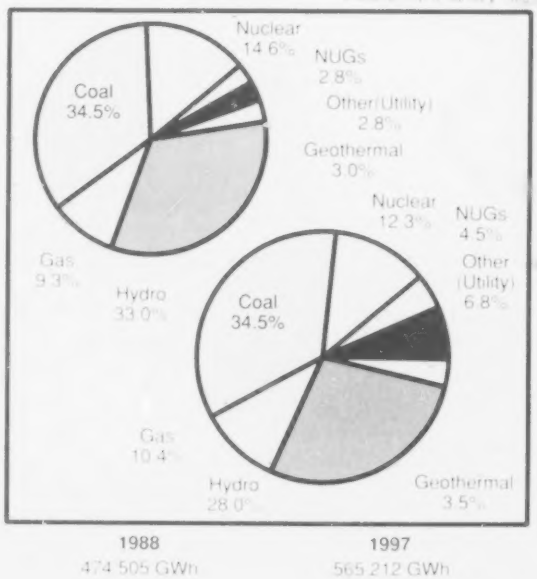
WSCC-U.S.

Generating Capacity by Fuel
Summer



WSCC-U.S.

Electrical Energy Production [a] by Fuel



into California. These operating restrictions are required to assure that acceptable system performance can be maintained in the event of a disturbance.

Several utilities within the Region are proceeding with plans to install phase shifting transformers in the transmission lines connecting Utah/Colorado and Arizona/New Mexico. The phase shifters are scheduled to be placed in operation during 1989-1991 and are expected to significantly mitigate the Region's major loop flow (parallel path flow) problems.

Regional Issues

The following are important issues which could have an adverse effect on future system reliability within WSCC.

- Deregulation and Increased Competition — The availability of surplus generation in some areas has led to increased competition between utilities to serve markets, particularly in California. Increased competition due to deregulation and transmission access may result in increased utilization of many transmission facilities (heavier line loadings for longer periods of time) with resulting reductions in transmission margins. As competition increases, and as the industry responds to competitive pressures, some utilities may be forced to greatly reduce communication and cooperation with competitors resulting in a decrease in overall system reliability.

- Economics versus Reliability — In planning electric power systems, the utilities have always recognized that economics and reliability must be considered collectively. The pressure to reduce rates in order to be competitive will result in a reduction in capital expenditures and operating expenses and an increase in the use of existing facilities. One consequence will be an increase in economy and firm electricity transfers between areas, and the use of complex operating nomograms to maximize the use of the existing transmission network. Many utilities are presently in the process of reassessing the need to provide margin in their transmission planning and operating studies. Historically, some utilities have built margin into their transmission systems to provide for the "unknown" after the project becomes commercially operational. Due to the changing economics of the utility industry, the need for this planning margin has become more difficult to justify, and as a result, very few utilities employ the concept of providing planning margin in their transmission system development. This, in turn, has led to the use of highly complex special protective schemes (remedial action schemes) and use of nomograms as a means of providing margin rather than the construction of new transmission. While the WSCC criteria have not been relaxed, there is a greater risk of system-wide disturbances due to reduced transmission margins.

- Changes in Planning Criteria — Due to the evolving economic considerations resulting from deregulation and transmission access issues, individual utilities and/or groups of utilities may choose to modify their internal reliability criteria to become more competitive. While this may lead to reduced reliability within some individual systems, the continued adherence to WSCC criteria will hopefully minimize effects on other systems and the Region as a whole.

- Non-Utility Generation — Non-utility generation accounts for 31% of the planned resource additions in WSCC during the next ten years. There is concern among utilities regarding the reliability and long-term availability of non-utility generation. Utilities have little control over the design, maintenance, or operation of such facilities. To date, some non-utility generating facilities have demonstrated adequate reliability, some have not. Experience with such facilities is limited and it is not known whether the owners of non-utility generation will have the same commitment to electric system reliability as to their own commercial ventures. Even though non-utility generation will, in most cases, have personnel experienced in the operation of their own facilities, there may be need for training in electric system operation. It is possible that additional utility generating capacity margins will be required for the same level of electric system reliability as more non-utility generating capacity is connected to the system.

- Parallel Path or Loop Flow — Loop flow, a natural outcome of interconnected system operation, affects both economics and reliability. In localized areas, the transmission system may operate with less margin and incur higher losses due to increased transmission line loadings resulting from loop flow. In other areas, just the opposite conditions may occur. These circumstances change as schedules and load conditions change. If a system must fully utilize its transmission capacity, the existence of loop flow could promote the reliance on additional complex special protective schemes to raise the transfer capability. This may also require the development of additional complex operating procedures.

It is clear that the evolving issues associated with deregulation, transmission access, economy versus reliability, and increasing competition will pose numerous challenges for the WSCC member systems in day-to-day system operation and in planning a reliable and affordable electric system for the future. Although the members of WSCC, through their coordination activities, are intent upon responsibly meeting these challenges, some of the burden of responsibility for a reliable and affordable electricity supply rests on the shoulders of the regulatory community.

WSCC Areas

Some specific activities within individual areas of WSCC are described below in terms of their impact on electric system reliability.

Northwest Power Pool Area

The Northwest Power Pool (NWPP) Area is comprised of the states of Washington, Oregon, Idaho, Utah, portions of Montana, Wyoming, Nevada, and California; and the Canadian provinces of British Columbia and Alberta. Projections of peak demand and energy requirements for the 1988-1997 period are somewhat reduced compared to last year's forecast. Winter generating capacity margins range from 27% to 20% over the assessment period and are judged to be adequate.

Low load growth within the Region has resulted in deferment of major facility additions other than the third ac Pacific Intertie and dc Intertie uprating to increase transfer capability from the Pacific Northwest into California.

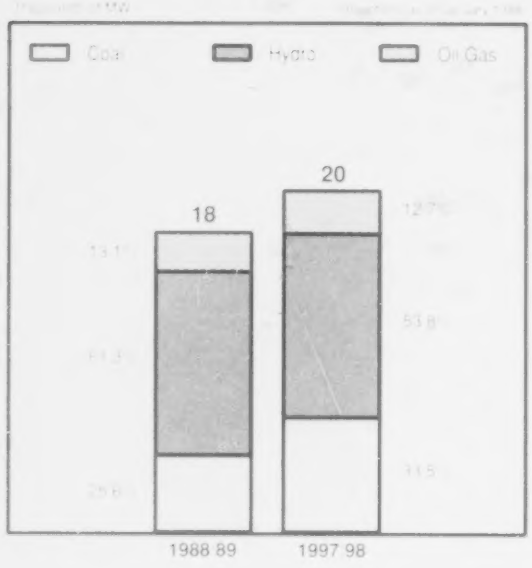
Planning for the third ac Pacific Intertie is continuing with energization scheduled for 1991. New facilities associated with the third ac Pacific Intertie include a new 500 kV line extending from central Oregon to southern Oregon and a third 500 kV line extending from southern Oregon to central California. The capacity of the ac Pacific Intertie will increase from 3,200 MW to 4,800 MW. With completion of the third ac Pacific Intertie line, the present Northeast/Southeast controlled islanding scheme will not be required for simultaneous loss of two 500 kV ac Pacific Intertie lines (with all three lines in service) as is now the case for two lines in service.

The dc Pacific Intertie uprate from 2,000 MW to 3,100 MW is presently in the construction phase. This project involves the addition of new dc terminals in parallel with existing facilities at the Celilo terminal in Oregon and the Sylmar terminal in southern California. Testing of the facility will begin in the late fall of 1988 with energization scheduled for early spring of 1989. Shunt capacitors will be installed at Malin Substation to maintain stability of the ac Pacific Intertie should an outage of the dc Pacific Intertie occur. Participants in the ac and dc Pacific Intertie upgrade projects are working together to coordinate their respective project facility requirements.

The reliability of remedial action schemes associated with the ac and dc Pacific Interties is being enhanced through the use of redundancy, new monitoring systems, and testing procedures. The Malin Substation is also being modified to a full breaker and one-half station to enhance reliability.

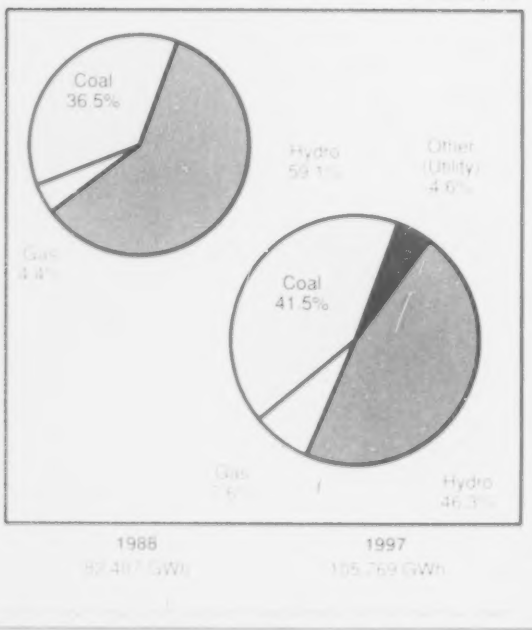
WSCC-Canada

Generating Capacity by Fuel
Winter



WSCC-Canada

Electrical Energy Production [a]
by Fuel



Rocky Mountain Power Area

The Rocky Mountain Power Area (RMPA) consists of Colorado, eastern Wyoming, and a small portion of Nebraska and South Dakota. This Area's 1988-1997 forecast of peak demand and annual energy is slightly lower than last year's forecast. The 1996 summer peak demand is 91 MW less and the 1996 annual energy load is 4,067 GWh less than last year's forecast. Summer generating capacity margins range between 31% and 26% for the next ten years and are judged to be adequate.

The generating capacity within the Rocky Mountain Power Area is surplus to the near-term load requirements within the Area. A significant amount of excess coal-fired generating capacity is available for Area load growth and export to other areas. Surplus generating capacity (approximately 1,000 MW) was available in the most recent summer and winter operating seasons. The export of surplus electricity is limited by the transmission capacity to outside areas. Load forecasts indicate that the surplus generating capacity will be available until the 1992 to 1995 period before being absorbed by Area load growth.

The 100 MW Nucla Fluidized Bed Combustion Demonstration Project, located in western Colorado, began initial operation during the second quarter of 1987, and is undergoing a two-year testing program. The testing program involves burning a wide-range of fuels and is intended to demonstrate higher boiler efficiency and air quality control without the necessity of scrubbers.

Several transmission projects are in progress or have recently been completed within the area to strengthen the system and enhance reliability as follows:

- The Rifle-San Juan 345 kV transmission line was placed in service during the third quarter of 1987. The line serves loads in western Colorado as well as strengthens the interconnected transmission system between Colorado and the Arizona-New Mexico area.

- The Hayden-Blue River 230 kV transmission line was placed in service during the fourth quarter of 1987. The line substantially increases transmission capacity between western and eastern Colorado.

- A third ac-dc-ac tie between WSCC and MAPP, located in southwestern Nebraska, is scheduled for operation in 1988. The transfer capability of the dc tie is 200 MW in either direction.

- Plans are under way to relieve the continuous heavy transmission loading problems in northern Colorado. Existing line sections are scheduled to be uprated or rebuilt during the next three to five years. In addition, a new 230 kV line in northern Colorado, between Ault and Ft. St. Vrain, is scheduled to be placed in service during the second quarter of 1990.

- Plans are in progress to construct a new 345 kV line between Colorado and Utah during the early 1990s. This line will ease the heavy transmission loading problems which currently exist between Colorado and Utah due to a combination of firm and economy electricity transfers and loop flow.

Loop flow continues to adversely affect the transmission system between the Arizona/New Mexico and Colorado/Utah areas. The effect has become significantly greater in western Colorado with the addition of the Rifle-San Juan 345 kV line. The existing transmission system in western Colorado will continue to be stressed with loop flow and firm economy electricity transfers. In an effort to mitigate this problem, the Western Area Power Administration is proceeding with plans to install phase-shifting transformers to control loop flow in the western Colorado portion of the interconnected system. In addition, several other utilities have recently announced plans to install phase-shifting transformers in the lines emanating to the south from Utah.

Continued reliance on remedial action schemes to increase transmission system transfer capability in WSCC and the Rocky Mountain Power Area exposes electric systems to adverse effects for both correct and incorrect operation of such schemes. While steps have been taken to improve the reliability and security of these schemes, the overall complexity is increasing. Mitigation of the adverse effects is still a concern.

Arizona-New Mexico Power Area

The Arizona-New Mexico Power Area (AZ-NM) consists of Arizona, most of New Mexico, and the western-most part of Texas. The 1988-1997 summer peak demand is projected to grow at 2.6% per year, however, the projected 1996 peak demand is 642 MW below last year's forecast. Annual energy is projected to increase at an average annual rate of 3.4% over the 1988-1997 forecast period. The current energy forecast depicts an increase in the 1996 annual energy load of 2,325 GWh compared to last year's forecast. Generating capacity margins during summer peak demand range between 28% and 22% for the next ten years and are judged to be adequate.

The Arizona-New Mexico Power Area utilities continue to forecast generating capacity levels which are significantly greater than their minimum capacity margins. The 1,270 MW Palo Verde Nuclear Generating Station Unit 3 was placed in commercial operation during the first quarter of 1988. The Area's share of Palo Verde Nuclear

Unit 3 represents approximately 30% of the Area's planned net generating capacity additions over the next ten years. The projected coal-fired and nuclear generating capacity additions total 1,615 MW for the 1988-1997 period.

Due to the surplus of resources in the Arizona-New Mexico Area, increased emphasis on marketing of generating capacity to neighboring utilities has become increasingly important to the maintenance of the economic health of Area utilities. In parallel with the completion of the third Palo Verde nuclear unit, seasonal cold shutdown of the Area's gas-, oil-, and coal-fired generating units is taking place. Area utilities are coordinating their generating unit cold shutdown programs to insure that capacity shortages are not inadvertently created during the fall, winter, or spring seasons.

The Arizona to California transmission system has been strengthened through the years; however, the capacity of the transmission system emanating to the west from the Four Corners generating plant is of concern. Heavier loadings are foreseen on this system due to contemplated major electricity purchase plans, resulting in a reduction in the level of capacity available for emergency situations. A second Devers-Palo Verde 500 kV line, currently under review by the California PUC, can increase the Arizona to California transfer capability and improve reliability in the long term.

Cogeneration and small power production has been and is being forecast to remain at a relatively low level. This is due to significant baseload coal-fired and nuclear generation within the Area having low energy costs, resulting in an overall low avoided cost for such power producers.

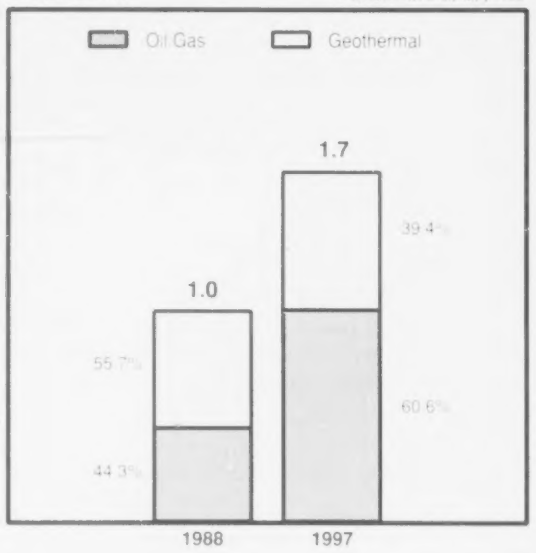
With the continuing economic incentives for California utilities to maximize Pacific Northwest imports, reliance on sophisticated remedial action schemes such as generation tripping and controlled system islanding continues while the schemes are becoming more complex. Should these remedial action schemes fail to operate as planned, the adverse effect on the Arizona-New Mexico Power Area and other Areas is a matter of serious concern. The Arizona-New Mexico utilities are actively working with California entities, both directly and through WSCC, to increase the assurance that the present and proposed Pacific Intertie remedial action schemes will not degrade system reliability in the Arizona-New Mexico Area.

California-Southern Nevada Power Area

The California-Southern Nevada Power Area encompasses most of California, southern Nevada, and the northern portion of Baja California, Mexico (WSCC-Mexico). The 1988-1997 summer peak demand forecast is slightly lower

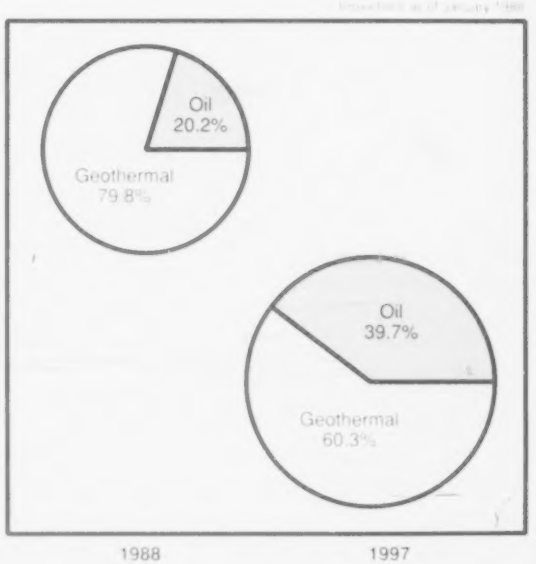
WSCC-Mexico

Generating Capacity by Fuel
Summer



WSCC-Mexico

Electrical Energy Production [a] by Fuel



than last year's forecast while the annual energy requirements are slightly higher. For example, the current peak demand forecast for 1996 is 1,622 MW lower than last year's projection while the projected 1996 annual energy load is 1,955 GWh higher. The current forecast projects summer peak demand and annual energy load to grow at 2.0% per year and 1.9% per year, respectively. Generating capacity margins during the summer peak range between 26% and 23% for the next ten years and are judged to be adequate.

The decline in gas and oil prices has allowed California utilities to generate more energy from their gas- and oil-fired units and has reduced their requirements for economy imports. This condition is expected to continue during 1988, though there are some indications that the natural gas bubble is diminishing.

A variety of non-utility generator additions has been placed in service in California within the past several years and more non-utility generation additions are projected in the future. These facilities include such generation types as solar, geothermal, wind, and cogeneration. Nearly 75% of the Region's existing non-utility generation is located in California and approximately 88% of the non-utility generation additions planned during the next ten years within the WSCC Region is in California.

Each type of facility addition presents its own unique operating characteristics and requirements. Of significant concern is the limited dispatchability of these resources and other issues which are being addressed in the regulatory arena and through negotiations with third-party developers.

In attempting to reduce rates, utilities are expanding efforts to reduce capital expenditures and operating expenses, and to increase the utilization of existing generation and transmission facilities. As a result, the operating margins originally designed into the system are decreasing, and utilities are evaluating the costs of their continued use of existing operating practices which were developed from many years of operating experience to assure system reliability. They are also striving to forecast the reliability and economic effects of changing these practices.

The use of nomograms to ensure stable system operation, while maximizing simultaneous electricity transfers between several areas, has increased the complexity of system operation. As complex as the nomograms are, there are indications that they may not address all potential operating conditions which could adversely affect system reliability.

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